ENVIRONMENTAL ASSESSMENT

GREAT RIVER ENERGY
CAMBRIDGE STATION

EQB Docket Number 05-92-PPS-GRE-CAMBRIDGE STATION
MPUC Docket ET-2/CN-05-347

Prepared by:
Minnesota Environmental Quality Board
http://www.eqb.state.mn.us/

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1.0 OVERVIEW

The Project. Great River Energy (GRE) is proposing to develop, construct, and operate a natural gas-fuel, simple-cycle electric generating peaking facility capable of producing 170 megawatts (MW).

Certificate of Need. GRE has applied to the Minnesota Public Utility Commission (PUC) for a certificate of need (CON) to construct a project consisting of a single simple-cycle combustion turbine (CT) at the site of its existing Cambridge Peaking plant located in Cambridge Township, Isanti County, Minnesota. The PUC determines whether the new large energy facility is needed and the size and type of any facility to be constructed. The PUC docket is ET-2/CN-05-347. As part of the consideration of an application for a CON, the PUC is required to prepare a document called an Environmental Report (Minn. Rules part 4410.7020).

Environmental Report. In the Environmental Report, the EQB addresses the environmental effects of the proposed project and the environmental effects of different types of facilities that might be constructed to meet the alleged need.

Site Permit. GRE is required to obtain a Site Permit from the Environmental Quality Board identifying the location upon which the new facility can be built (Minn. Stat. § 116C.57, subd. 1). As part of the consideration of an application for a Site Permit, the EQB is required to prepare a document called an Environmental Assessment (Minn. Stat. § 116C.575, subd. 5).

Environmental Assessment. In the Environmental Assessment, the EQB evaluates the potential impacts of the project at the site proposed by the applicant and at possible alternative sites that are identified and discusses ways to mitigate these potential impacts.

Joint Hearing. The EQB is required to hold a public hearing on the application for a site permit (Minn. Stat. § 116C.575, subd. 6). The PUC is required to hold a public hearing on the application for a certificate of need (Minn. Stat. § 216B). Minnesota law allows the Public Utilities Commission and the Environmental Quality Board to consolidate a certificate of need proceeding and a permitting proceeding, producing one Environmental Review Document and holding one public hearing. Minn. Stat. § 216B.243, subd. 4. The hearing is anticipated to be scheduled for May 2005.

Interested persons will have an opportunity at the hearing to ask questions about the project and to make comments that will become part of the administrative record. The hearing examiner will ensure that the record created at the hearing is preserved and transmitted to the board.

Major Decisions. The first decision that will be made in this matter is a decision by the Public Utilities Commission whether there is a need for additional electric power. In the course of deciding whether additional electric power is needed, the Public Utilities Commission must also determine the size and type of any new facility to be constructed to meet the need that is found. If the Public Utilities Commission determines that there is a need for additional power, it will issue a certificate of need for a particular size and type of facility. The EQB, then, must determine the appropriate location for this new facility. The only site under review in this proceeding is the Cambridge Station site proposed by GRE.

The final decision on the issuance of the site permit will be made by the full EQB Board. It is anticipated that this matter will come before the EQB Board for a final decision at its monthly meeting in July, 2005.

2.0 INTRODUCTION

Great River Energy (GRE) filed an application for a Certificate of Need (CON) with the Minnesota Public Utilities Commission (Commission) for the Cambridge Station project on February 28, 2005 in accordance with Minnesota Rules Chapter 7829 and 7849.

On March 11, 2005, GRE submitted to the Minnesota Environmental Quality Board (MEQB) a site permit application regarding a proposal to construct and operate a natural gas-fired, simple-cycle electric generating peaking facility capable of producing 170 megawatts (MW) pursuant to the Minnesota Power Plant Siting Act (Minnesota Statutes 116C.51 through 116C.69) and Minnesota Rules Chapter 4400. GRE informed the EQB of its intension to follow the Alternative Permitting Process (Minnesota Rules 4400.2000)

GRE requested that the EQB and the Minnesota Public Utilities Commission (PUC) consider consolidating the environmental review and public hearings in this case (Minnesota Rules 4410.7060 and Minnesota Statutes § 216B.243, Subd. 4).

On March 14, 2005, the EQB Chair notified the applicant in writing of the acceptance of the application as substantially complete and that the application would be reviewed in accordance with the alternative permitting review procedures. Additionally, the Chair elected to combine the general environmental review (i.e., Environmental Report) for the PUC with the site-specific environmental review (i.e., Environmental Assessment) for the EQB into one document. The EQB rules specifically allow for such accommodation. Minn. Rules part 4410.7060.

On March 17, 2005, the EQB passed a resolution authorizing a joint hearing to be held to consider both the Certificate of Need (CON) application and the Site Permit application.

The EQB docket number for this proceeding is 05-92-PPS-GRE Cambridge Station.

On April 8, 2005, the PUC issued an order finding the CON application substantially complete and authorizing the holding of joint public hearing on need and siting.

The PUC docket number for this proceeding is ET-2/CN-05-347.

2.1 PROJECT DESCRIPTION

GRE proposes to construct a 170 MW, natural gas-fired, simple cycle combustion turbine generator at its existing peaking plant site near Cambridge in Isanti County, Minnesota (**Figure 1**). The proposed facility will be located on a current generating site, approximately 13 acres in size, owned by GRE. The site currently has a 25 MW, fuel oil-fired, combustion turbine generator and associated substation.

The Cambridge Station property is bisected by 349th Avenue Northeast. The larger, southern portion of the site is an approximate 11-acre parcel in Section 21, T36N, R23W; this portion houses the existing fuel oil-fired combustion turbine generator (CTG) and associated substation.

The smaller, northern portion of the site is an approximate 2-acre parcel in Section 16, T36N, R23W that houses a service building.

The property is bordered by agricultural land to the north, east and south; the property is bordered along its western boundary by the Burlington Northern Santa Fe railroad and further west by State Highway 65.

The layout of the current property is shown in **Figure 2**.

The Cambridge Station will operate as a peaking facility to provide electric energy during times of peak demand. The plant is expected to have a short start-up sequence at 8 minutes, and the ramp rate is expected to be 12 MW per minute.

GRE expects an annual capacity factor of between 5 and 10 percent (438-876 hours) based on GRE's operating experience at the Pleasant Valley Station in Mower County and the Lakefield Junction Station in Jackson County. The new unit will be effectively limited to a total of about 3,000 hours of operation per year (which would correspond to an annual capacity factor of about 30 percent) because of air quality permit pollutant emission limits. GRE anticipates the unit will have at least a 30-year operating life.

The energy efficiency of the new combustion turbine generator is expected to be in the range of 35 to 37 percent, depending on operating conditions. Operational characteristics are summarized in **Table 1**.

2.1.1 DESCRIPTION of POWER GENERATING EQUIPMENT and PROCESSES

A simple cycle combustion turbine has three major components: (1) a compressor, (2) a combustion chamber, (3) and a turbine. Air is drawn into the compressor, compressed, discharged to the combustion chamber, mixed with fuel and ignited. The resulting expanding hot gases are sent through the turbine blades, causing them to rotate. The rotating turbine blades turn a shaft connected to a generator that produces electricity. Exhaust gasses are emitted to the atmosphere through a stack that is expected to be about 90 feet tall. This process is shown schematically in **Figure 3**.

The combustion turbine generator for the project will be "F" class technology, such as a Siemens Westinghouse Model V84. The project will be one of the most efficient simple-cycle generation sources in the region due to this technology. The CTG will have a nominal summer capacity of about 170 MW.

In addition to the CTG, new plant equipment will include:

- a generator step-up transformer,
- less than 1,000 feet of transmission line from the transformers to the existing Cambridge Substation,

- a natural gas town border station and meter,
- an evaporative cooler, and
- an exhaust stack with silencer.

These items comprise the largest components of the CTG plant. The proposed generating plant layout is shown in **Figure 4**.

2.1.2 AIR EMISSION CONTROL EQUIPMENT

Natural gas combustion generates significantly less particulate matter than oil or coal, and very little sulfur dioxide or other trace air emissions. Uncontrolled natural gas combustion does produce nitrogen oxides (NO_X) and carbon monoxide (CO).

Air emission control equipment at the new Cambridge Station will include dry low-NO_X (DLN) combustors to reduce NO_X emissions. Emissions of carbon monoxide (CO), volatile organic compounds (VOC), sulfur oxides (SO_X) and particulate matter (PM_{10}) will be controlled through fuel selection and operational controls (combustion control, operating load, and firing temperature).

Dry low NO_X (DLN) combustor technology premixes air and a lean fuel mixture, which significantly reduces peak flame temperature and thermal NO_X formation. Conventional combustors are diffusion controlled, injecting fuel and air separately, resulting in hot spots that produce high levels of NO_X. In contrast, DLN combustors operate in a "premixed mode" where air and fuel are mixed before entering the combustor, thus reducing the production of NO_X. Additionally, in DLN combustors the amount of NO_X formed does not increase with residence time, allowing the DLN system to achieve low CO and unburned hydrocarbons (UHC) emissions while maintaining low NO_X levels.

2.1.3 WATER USE

The current on-site water well is designed for domestic-type use and is not suitable to meet the proposed Cambridge Station water needs. GRE plans to construct a new well on the site south of 349^{th} Avenue NE. This well will provide water for evaporative cooling and other minor uses such as equipment washing. GRE will apply for a water appropriations permit from the MDNR after the new well is constructed and tested.

Simple cycle combustion turbine technology can operate without water, except that required for fire protection. However, the proposed Cambridge Station will include the capability to use water to provide evaporative inlet air cooling and potentially wet compression power augmentation to sustain the cooler weather capacity of the CTG during the warmest days of the year. It is estimated that the proposed unit will operate without using any water for more than 80 percent of the time. Evaporative cooling is anticipated to be used to cool the air entering the units up to about 20 percent of the time. Air is cooled through humidification by allowing water to flow over a fabric or cellular media at the inlet to the combustion turbine. The evaporative cooling process consumes a relatively small amount of water, but increases electricity output by approximately 3 to 5 percent depending on the ambient relative humidity.

A water use diagram that summarizes water use and wastewater generation from the operation of the new CTG is shown in **Figure 5**. Total estimated annual groundwater appropriation for the proposed Cambridge Station project is estimated at 4.7 million gallons with an estimated groundwater withdrawal rate of 108 gallons per minute.

Two water storage tanks will be provided on site. One 300,000-gallon tank will store raw water, and one 200,000-gallon tank will store treated water. Treated water will be used for operation of the evaporative cooler during the summer months and potentially for wet compression power augmentation. Raw water will be used as supply for the water treatment system, for fire suppression, and other ancillary plant uses. A transportable demineralization unit will be used to treat the raw water. The demineralization beds will be recharged off site; therefore, no on-site wastewater discharge will occur from the demineralization system.

The well will likely withdraw water from the Prairie du-Chien/Jordan bedrock aquifers. The estimated annual groundwater appropriation for the Project is relatively small and is not expected to result in any adverse impacts on the aquifer and regional water supplies. Prairie du-Chien/Jordan aquifer wells are generally highly productive, and it is not uncommon for them to produce in excess of 1500 gpm. The City of Cambridge does not obtain its municipal water supply from the Prairie du-Chien/Jordan bedrock aquifer. The city obtains its water from the deeper Mount Simon aquifer. Therefore, it is not anticipated that the proposed 150-gpm appropriation rate will have an adverse impact on any existing wells in the area.

2.1.4 WASTEWATER

The only source of wastewater from operation of the facility will be the evaporative cooler. When the evaporative cooler is in operation, approximately 15-75 gallons per minute of blow down wastewater will be generated. The actual blow down rate will be determined based on water quality data for the site. This wastewater will be discharged to an on-site retention basin and will then be discharged off site along with site storm water in accordance with a new National Pollution Discharge Elimination System Discharge Permit (NPDES) to be issued by the Minnesota Pollution Control Agency (MPCA).

An estimated 150,000 gallons of wastewater (compressor wash water) will be generated annually from maintenance of the CTG. This process wastewater will be stored in an on-site tank. The process wastewater will be off-loaded into tanker trucks and hauled to a municipal wastewater treatment plant for ultimate treatment and disposal.

2.1.5 SOLID AND HAZARDOUS WASTE GENERATION

The Cambridge Station plant will use and store on site a small number of chemicals. **Table 2** lists the chemicals a generating facility of this size and type typically uses. The chemicals include mineral oil and sulfur hexafluoride for insulating transformers and switchyard equipment, lubrication oil for lubricating CTG bearings, diesel fuel for operating the fire water pump, and various liquid detergents for washing the CTGs.

All chemical storage areas will have appropriate secondary containment (i.e., concrete floors, concrete curbing, etc.). Areas that have the potential for oil or lubrication spills will also be protected by containment structures (i.e., concrete floors, concrete curbing, etc.). Lockable drain valves will be used where appropriate. Where present, floor drains will be directed to an oil/water separator, holding tanks or chemical collection/treatment facilities.

GRE will privately contract with local waste haulers for collection and disposal of all non-hazardous solid wastes generated at the facility. In the unlikely event that wastes generated during maintenance activities are determined to be hazardous as defined by the Resource Conservation and Recovery Act (RCRA)[1], they will be managed in accordance with applicable requirements. It is anticipated that the High Bridge plant will be categorized as a very small quantity generator (VSQG) under Minnesota Rules Chapter 7045. To be eligible for VSQG classification, the facility must generate less than 220 lbs of non acute hazardous waste per month. This type of generator can not accumulate more than 1,000 kg or 2,200 lbs of waste on-site before delivering the waste to a permitted Treatment, Storage and Disposal (TSD) Facility.

2.1.6 FUEL SUPPLY

Natural gas will be the only fuel used to generate electricity in the new CTG. A ½-mile, 20-inch diameter lateral natural gas pipeline will be constructed off Northern Natural Gas Pipeline's 16-inch trunk-line. A natural gas town border station and gas metering/conditioning station will be constructed at the site.

GRE anticipates purchasing Interruptible Transport (IT) service from NNG. If significant winter operation is anticipated, GRE may pursue purchasing firm transport capability on the secondary market. In addition, GRE will take advantage of some of NNG's tariffed balancing services to optimize operation of the project while insuring an adequate supply of natural gas for variable operations.

At full load, the new CTG will burn 1,546 million metric cubic feet (MCf)/hour during summer operation and 1,771 MCf/hour during winter operation. Assuming a 10 percent capacity factor (operating for 876 hours per year), the Cambridge Station will burn about 1.4 to 1.5 million MCf of natural gas annually.

2.1.7 CONSTRUCTION

Mobilization at the site will be the first construction activity, with GRE setting up field offices and the contractor following with mobilization and setup of construction offices, security fencing and entrances.

[1] Minnesota State Hazardous Waste and Tanks Rules, Chapter 7045 (http://www.pca.state.mn.us/waste/hw_mnrules.html)

Upon approval from all governmental bodies with jurisdiction over this project, construction will begin. The area where the new turbine will be located will be excavated approximately 2-4 feet to prepare the area for pouring of concrete footings and foundations. Preliminary geotechnical investigations indicate that pilings will not be required and that the surficial groundwater table is deep enough below grade that dewatering will not be necessary for construction of foundations. Underground services will be installed. At the same time, the foundations for the generator step-up transformer and miscellaneous equipment will be formed. Extensive concrete work for all foundations will follow. Rough-ins for cable and pipe will be installed in the various foundations.

Within two to three months of initial mobilization, deliveries will begin arriving at the site. These shipments will continue over a four to five month period. Shipments of the transformer, turbine and generator will likely be via rail, with other equipment likely being shipped by truck. The timing of these shipments will coincide with the completion and readiness of their respective foundations. Shipments at the rail siding in Cambridge and at the plant site will be coordinated by the contractor's heavy haul subcontractor. This equipment will be lifted from the rail cars and loaded onto transport vehicles to be driven on site. A construction crane will be located on site to lift large equipment from transport vehicles onto foundations.

The combustion turbine, generator, and transformer for the new generating unit will be set first, followed by the remaining auxiliary equipment. Erection of the turbine's modular air inlet and the exhaust stack will take place next. The greatest number of on-site workers will be present during the erection of the turbines, detailed wiring and piping, and while work is being performed in the Cambridge Substation.

Northern Natural Gas will be constructing the gas pipeline while the site work is being completed. The pipeline is planned to enter at the center of the site's south property line. The pipe will extend underground to a gas metering and regulating building. A contractor will take the pipeline from this point and run it underground to the turbines.

GRE will be constructing an overhead 69-kV line from the generator step-up transformers to the Cambridge Substation as plant work nears completion. Work will also be ongoing in the substation to install breakers, transformer and additional protection devices. During final stages of construction activities will include installation of the inlet air filter and bird screen, and completion of equipment platforms, insulation and painting.

Pre-operational testing will take place for one to two months in preparation for start-up of the new unit, currently targeted for May 2007. The initial turbine start-up requires a two-week schedule. During the first few days of operation, gas will be fired in the combustion unit without placing a load on the turbine in order to bring the combustion unit up to full speed. Next, the turbine will be run and synchronized with the grid at a low load. Subsequently the unit's output will be slowly raised to its maximum capacity while testing the performance of various plant systems.

After the completion of testing, GRE and the contractor will begin to demobilize. By early Fall 2007, trailers, construction equipment and temporary fencing are expected to be removed from the site.

2.1.8 ELECTRICAL INTERCONNECTION

One generator step-up transformer will be used to increase the voltage, from the CTG at a lower voltage (13.8 -16 kV), up to the substation voltage of 69 kV. Upgrades to the substation will be part of the proposed project. In addition, three of the four transmission lines that enter the Cambridge Substation will require upgrades as part of the proposed project. In total, approximately 47 miles of transmission line are expected to be upgraded (**Figure 6**). These upgrades will consist of reconductoring or rebuilding to meet current state-of-the-art 69-kV design. Details of the interconnection will be finalized once the interconnection studies have been completed and a final interconnection recommendation is provided by the Midwest Independent System Operator (expected by mid-summer 2005).

2.1.9 PIPELINE

The Cambridge Station will require a new natural gas pipeline to bring natural gas to the facility.

The new gas pipeline will likely consist of a 20 inch diameter, steel pipeline, operating at a pressure of 550-700 pounds per square inch (PSI). The pipeline will originate from the Northern Natural Gas (NNG) interstate pipeline, approximately 0.5 miles to the south (**Figure 7**).

2.2 PURPOSE

GRE states that the Cambridge Station project is necessary to ensure adequate generating capacity in 2007 and beyond to reliably meet customer demand for electricity. The need for the addition of peaking units at the Cambridge Station is described in more detail in GRE's application for a CON before the PUC.

2.3 SOURCES OF INFORMATION

Much of the information contained within this document was provided by the applicant or the applicant's representatives (Barr Engineering Company) in the form of the Application for a Site Permit, the Certificate of Need Application, and subsequent correspondence.

Additional sources of information are listed below:

- Minnesota Pollution Control Agency (http://www.pca.state.mn.us/)
- Minnesota Department of Natural Resources (http://www.dnr.state.mn.us/index.html)
- Minnesota Department of Health (http://www.health.state.mn.us/)
- Minnesota Department of Commerce
- Minnesota Public Utilities Commission (http://www.puc.state.mn.us/index.htm)
- U. S. Environmental Protection Agency (http://www.epa.gov/)

- Electric Power Research Institute (http://www.epri.com/default.asp)
- U. S. Department of Agriculture Natural Resources Conservation (http://soils.usda.gov/about/)
- Minnesota Geological Survey (http://www.geo.umn.edu/mgs/)
- Department of Administration, State Demographic Center (http://www.demography.state.mn.us/)
- Federal Emergency Management Agency (http://www.fema.gov/)
- EQB Docket No. 02-48-PPS-FEP (http://www.eqb.state.mn.us/Docket.html?Id=3217)
- U. S. Department of Energy, Energy Information Administration (http://eia.doe.gov/)
- Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005

3.0 REGULATORY FRAMEWORK

Typically, a certificate of need from the Minnesota Public Utilities Commission (PUC) is required for a proposed large energy project. The proposer of a large energy project must establish through a certificate of need application, that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures. Minn. Stat. § 216B.243. A certificate of need must be granted by the PUC before the EQB can issue a Site Permit for a new large power plant.

The Minnesota Legislature has established a state policy to locate large electric power generating plants in an orderly manner compatible with environmental preservation and the efficient use of resources. The EQB has the responsibility for siting power plants over 50 MW. The legislature directed the EQB to designate sites that minimize adverse human and environmental impact while ensuring continuing electric power system reliability and integrity and ensuring that electric energy needs are met and fulfilled in an orderly and timely fashion.

3.1 CERTIFICATE OF NEED

A Certificate of Need is required for the proposed Cambridge Station project.

GRE filed an application for a Certificate of Need (CON) with the Minnesota Public Utilities Commission for the Cambridge Station project on February 28, 2005, in accordance with Minnesota Rules Chapter 7829 and 7849.

On April 8, 2005, the PUC issued an order finding the CON application substantially complete and authorizing the holding of a joint public hearing on need and siting.

The PUC docket number for this proceeding is ET-2/CN-05-347.

3.2 SITE PERMIT REQUIREMENTS

Under the Power Plant Siting Act (Minnesota Statutes §§ 116C.51-.697) a site permit from the Minnesota Environmental Quality Board is required to build a large electric power generating plant (LEPGP). The EQB has adopted rules for the administration of power plant site permits (Minnesota Rules Chapter 4400).

There are two processes available for permitting LEPGPs depending on the type and size of the proposed project. One process, called the Full Review Process, requires the preparation of an Environmental Impact Statement, the holding of a contested case hearing conducted by an administrative law judge (ALJ), and the identification of an alternative site and may take up to one year to complete the permitting process.

In the other process, the Alternative Review Process, a shorter environmental review document termed an Environmental Assessment is prepared; a less formal public hearing is held; the applicant does not have to identify an alternative site, and the process may take up to six months.

The proposed Cambridge Station project is eligible for the Alternative Review Process since power plants fueled by natural gas are eligible for the shorter process. Minnesota Statutes Section 116C.575.

On April 19, 2005, a public meeting was held by the MEQB staff at the Community Hall Building, Isanti County Fairgrounds, to discuss the proposed Cambridge Station project with interested persons and to solicit input into the scope of the Environmental Assessment. The public also had an opportunity to ask questions during informal discussions with company representatives. The public was given until 5:00 pm on April 28, 2005, to submit written comments.

No public comment letters were received. The Chair of the EQB issued a Scoping Order on April 29, 2005 (**Appendix A**).

3.3 RURAL UTILITY SERVICE

GRE may obtain financing for the Cambridge Station project through the Rural Utility Service (RUS), an agency within the United States Department of Agriculture (USDA). The use of RUS funding triggers the requirement for environmental review for the plant site and the associated transmission line modifications under the National Environmental Policy Act (NEPA).

In accordance with the National Environmental Policy Act (NEPA), RUS must consider the environmental effects of each of its proposals on the human environment. In 1978, the Council on Environmental Quality (CEQ) promulgated regulations to implement the procedural provisions of NEPA. In order to implement NEPA at the agency level, the CEQ directed agencies to adopt procedures to supplement their regulations. RUS's procedures are found at 7 CFR 1794. These regulations classify the agency's actions into levels of environmental review (i.e., Categorical Exclusions, Environmental Assessments, or Environmental Impact Statements) and describe agency-specific implementing procedures. To further the intent of NEPA and the CEQ procedures, RUS incorporates all of its environmental compliance activities, including the National Historic Preservation Act, under its NEPA review umbrella.[2]

RUS administers its programs through Rural Development State Offices. Each Rural Development State Office has a State Environmental Coordinator (SEC) who provides oversight and direction in the implementation of RUS's environmental review responsibilities at the state level.[3]

For all project proposals that require construction, RUS normally requires its applicants to prepare Environmental Reports concurrently with Preliminary Engineering Reports. This requirement meets the CEQ's intent whereby agencies "integrate the NEPA process with other planning at the earliest possible time to insure that planning and decisions reflect environmental values". In order to outline the types of information RUS needs in the Environmental Reports, the RUS prepared and issued a series of bulletins.[4]

[2] http://www.usda.gov/rus/water/ees/environ.htm
[3] Ibid
[4] Ibid

The RUS website contains reference, guidance, and training materials that explain what is required under RUS program requirements. Resources include an Environmental Library that contains text versions of pertinent environmental statutes, regulations, Executive Orders and other common guidance documents.

3.4 JOINT HEARING

Minnesota law allows the Public Utilities Commission and the Environmental Quality Board to consolidate a certificate of need proceeding and a permitting proceeding and hold one public hearing. Minn. Stat. § 216B.243, subd. 4. The EQB recognizes in its rules that a joint hearing can be held in appropriate situations. Minn. Rules part 4400.1800, subp. 3. In deciding whether to consolidate the hearings, the two agencies consider whether consolidation is feasible, more efficient, and may further the public interest.

On March 17, 2005, the EQB passed a resolution authorizing a joint hearing to be held to consider both the Certificate of Need (CON) application and the Site Permit application.

On April 8, 2005, the PUC issued an order authorizing the holding of a joint public hearing on need and siting.

3.3 OTHER PERMITS

Table 3 contains a list of the anticipated permits and associated environmental approvals required for the Cambridge Station project. Compliance with the terms of all applicable and relevant regulatory permits and approvals will be a condition of any Site Permit issued by the Board.

Air Quality Permit

An application for an amendment to the current Cambridge Station plant air emission permit, Permit No. 05900014-001, will be submitted to the Minnesota Pollution Control Agency (MPCA) to accommodate the proposed project.

Water Appropriations Permits

GRE expects to install a new well at the Cambridge Station site in 2006 to meet the water needs of the proposed project. GRE will submit an application to the Minnesota Department of Natural Resources (MDNR) for a groundwater appropriation permit immediately after the well construction is completed.

National Pollutant Discharge Elimination System (NPDES) Discharge Permit

GRE plans to dispose of storm water and process wastewater under a National Pollutant Discharge Elimination System (NPDES) discharge permit. Application for an NPDES permit is expected to be made to the Minnesota Pollution Control Agency (MPCA) in the second half of 2005.

NPDES Stormwater Program

The proposed Cambridge Station project will disturb more than one acre of land and therefore triggers the requirement to apply for coverage under the MPCA's NPDES Stormwater Permit Program for Construction Activities. GRE will require its contractor to apply for and comply with the construction storm water permit.

High-Voltage Transmission Line Route Permit

Transmission lines connecting the Cambridge Station to four area substations will be upgraded with new conductors and new poles. The Cambridge-Princeton line is being upgraded independent of the proposed project to address reliability issues. The three other lines will require upgrades due to the Cambridge Station CTG installation. No change in voltage of the existing 69-kilovolt (kV) lines is planned; therefore, no EQB High Voltage Transmission Line Route Permit is required. An MDNR License to Cross Public Waters will be obtained for public waters and wetlands crossed by the transmission lines. GRE will also obtain local building permits that may be required for the transmission line work.

Gas Pipeline Route Permit

GRE will obtain natural gas for the Cambridge Station project from Northern Natural Gas Company (NNG), an interstate pipeline company. NNG will construct and own a new lateral gas pipeline connecting the Cambridge Station site with an existing interstate pipeline approximately ½ mile from the site. A town border station will be constructed on the Cambridge Station site. Because the gas supply is being provided through an extension to an interstate pipeline, a gas pipeline routing permit in accordance with the requirements of Minnesota Statutes 116I.015 and Minnesota Rules Chapter 4415 is not required. NNG will apply for permits under the federal interstate pipeline permitting processes as required. NNG will also obtain other necessary permits for the gas pipeline construction, which may include:

- MPCA NPDES General Stormwater Permit for Construction Activity,
- MDNR License to Cross Public Lands and Waters,
- MDNR Wetland Replacement Plan Application,
- U.S. Army Corps of Engineers Section 404 Wetland Permit, and
- Road Crossing Permits (Mn/DOT, Minn. Rules Chpt. 8810).

Miscellaneous Permits

The Cambridge Station may require permits, approvals or notifications under the following programs:

- Exemption to allow burning of natural gas for power production (DOE, 10 CFR chapter 503)
- Road Crossing Permits (Mn/DOT, Minn. Rules Ch. 8810)

- State Building and Construction Permits and Inspections
- Local Building and Construction Permits and Inspection

4.0 ALTERNATIVES TO THE PROPOSED LEPGP

Under Minn. Rules part 4410.7035, subpart 1, the Environmental Assessment must include certain items with regard to the alternatives that are considered. These items include a general description of the alternatives considered, an analysis of the potential human and environmental impacts of these alternatives and possible mitigative measures, and an analysis of the feasibility and availability of each alternative. In this case the scoping order identifies the following alternatives that will be analyzed in this document: the no build alternative, demand side management, purchase power, alternative fuels (fossil fuel technologies and renewable resource technologies), up-grading existing facilities, and new transmission. Each of these alternatives is addressed in turn below.

4.1 NO-BUILD ALTERNATIVE

Description. The no-build alternative means that GRE does not build anything. Electric power will continue to be supplied in the manner and with the facilities that are presently in existence.

Impacts. Often, in conducting environmental review, the analysis of the no-build alternative involves a discussion of the environmental impacts of continuing the status quo. For example, with a proposed highway project, the no-build alternative would take into account the impacts associated with continuing to have traffic increase along existing roads and highways and for development to occur along these existing arteries.

When a certificate of need is required for a proposed project, however, the no-build alternative takes on a different aspect. If the PUC determines that the need for additional power has not been established, no certificate of need will be issued and nothing new will be constructed. Whatever impacts would result from the expansion of the Cambridge Station plant will not occur.

If no new facility is authorized, the potential impacts are twofold. One, there could be a shortage of electricity, with all the ramifications that result from a shortage of electricity on hot days in the summer. Two, the electricity will come from someplace else, with the impacts that result from the generation and transmission of electricity from these other sources. These impacts are explored below with the various alternatives.

Feasibility and Availability. The no-build alternative is not one that requires any analysis regarding its feasibility or availability.

4.2 DEMAND SIDE MANAGEMENT

Description. Demand side management (DSM) is the practice of reducing customers' demand for energy through programs such as energy conservation and load management so that the need for additional generation capacity is eliminated or reduced. More detail on GRE's conservation and load management programs is available in Appendix C of GRE's Certificate of Need Application, dated February 28, 2005.

Impacts. Demand side management can minimize environmental effects by avoiding the construction and operation of new generating facilities. Those impacts that would result from the construction of the proposed facility, or from the supply of the additional power through other means, would be avoided if DSM were sufficient to reduce the need for additional power.

Feasibility and Availability. A determination of whether demand side management can reduce the anticipated need for additional power is what the Public Utilities Commission will determine in the certificate of need proceeding. A conclusion that DSM will eliminate the need for additional power is essentially a decision to deny the requested certificate of need.

The only information reviewed for this document regarding the feasibility of DSM is that information provided by GRE in its Certificate of Need Application, dated February 28, 2005. GRE concludes in its application that DSM is not a feasible alternative to the proposed project.

Through the use of load management and conservation measures, GRE reports that it reduced its summer peak demand in 2004 by 300 MW. This was achieved primarily through load management programs such as residential cycled air conditioners, interruptible irrigation, peak shave water heaters, and customer owned generation. GRE expects to see continued, significant growth in these programs. In 2005, the impact of demand-side management programs on summer peak reduction is expected to increase by another 16 MW. The success of these programs has delayed the need for additional peaking power; however, it is infeasible that an additional increase in the participation of these programs could entirely replace the 170 MW capacity of the proposed project.

Additional conservation does present some limitations. First, changes to demand behavior require time to develop. Given GRE's time-table, an additional 170 MW savings during peak usage may not be achievable by 2007. Such a change would represent over a 50-percent increase above current programs and participation. Further, successful programs will see diminished increases as the market for participation becomes saturated.

4.3 PURCHASED POWER

Description. Purchased power is exactly what it says – the purchase of electricity from another entity. Utilities like GRE enter into power purchase agreements with other generators of electricity. A power purchase agreement is a contract between a wholesale supplier of electricity and an entity that sells the energy to retail consumers.

In addition to generating electricity at its 11 major generating plants in Minnesota, Wisconsin, and North Dakota, GRE relies on both short-term and long-term power purchase agreements to satisfy the demand for electricity in its Minnesota service area and to meet the Mid-Continent Area Power Pool (MAPP) capacity reserve requirements. (MAPP requires power suppliers to have sufficient accredited generation capacity to provide 15% reserves above the actual summer peak demand.) Short term power purchase agreements are normally for a two or three month period, often the summer peaking time. Long term agreements usually provide for the purchase of power over a ten or even twenty year period.

Impacts. The environmental impacts associated with the purchase of electricity depend for the most part on how the electricity that is purchased was generated. Presently, GRE purchases power totaling 100 MW (summer rating) from the Western Area Power Administration and other power purchases. This electricity comes from various sources, including some from coal-fired power plants and some from hydro facilities. It is difficult to discuss with any specificity what the comparable impacts are at this juncture because how the purchased power is generated is unknown.

Feasibility and Availability. GRE sought proposals, through a request for Proposal (RFP) process, for a variety of resources in March 2004. Thirty-one proposals from 17 entities were received in response to the Peaking and Intermediate portion of the RFP. Only five of the 31 bids included the use of existing generating sources. The remaining proposals relied on new generating sources. GRE through the RFP review process determined that the self-build option was superior to the other proposals on a cost and responsiveness basis.

GRE states that the self-build option has some definite benefits over purchasing capacity and energy from other entities. GRE's status as a cooperative affords it some financial advantages including low-cost financing and lower overhead due to its being a not-for-profit organization. These facts were reflected in GRE's overall proposal price. Purchase power contracts are typically less flexible than desired for a peaking source. Purchases generally require scheduling energy on a day-ahead basis with limited flexibility intraday to respond to unexpected changes in load, availability of other owned resources and the impact of real time transmission availability to support short-term energy purchases.

A GRE-owned generation resource can be ramped up and down to follow load and to allow maximizing the dispatch of its other resources. In addition to long-term contracting of capacity and energy needs typically met through an RFP process, GRE will continue to use spot market purchases to meet its short-term obligations whenever the market is economically competitive.

GRE's recent experience has been that its energy schedules from spot market purchases are often cut at the highest peak times due to transmission constraints on the grid. While the new MISO market may assist in delivering energy, the transmission constraints will be reflected in the price rather than through cut schedules. Thus, GRE's assessment is that the availability of this type of purchase is unreliable and, if available, would not be as economic as a self-build option.

4.4 ALTERNATIVE FUELS

One of the issues to be examined in the Environmental Assessment is the possibility of using a different energy source than the one proposed by the project proposer. In this case GRE has proposed to install a natural gas-fired simple cycle turbine. In its Certificate of Need Application, GRE addressed to some extent a number of other possible types of facilities that burn fossil fuels, along with renewables.

Coal Fired Boiler

Description. This option is the burning of coal to generate electricity. Coal plants are generally baseload plants that operate nearly all the time. The Coal Creek Station in Underwood, N.D. (1,114 MW) and the Stanton Station in Stanton, N.D. (188 MW), are examples of two baseload coal plants owned by GRE.

Impacts. The direct environmental impacts of coal burning include air emissions, solid waste (ash) generation, rail traffic, and waste heat discharge to air and water. Burning coal results in the emission of various air pollutants, including sulfur dioxide, nitrogen oxides, particulate matter, mercury, carbon monoxide, and carbon dioxide.

Feasibility and Applicability. A coal-fired facility may serve as an intermediate load unit; however, coal-fired power plants are best suited for base load (steady, high-capacity) duty. Coal-fired units are not well suited to operate as peaking plants because of the long lead time (a day or more) necessary to bring a coal-fired plant online at full capacity.

Operating a coal-fired facility as a peaking facility by keeping it in "stand-by" mode greatly reduces the efficiency and increases emissions. Further, it increases the wear and tear on the equipment, which can lead to more frequent forced and planned outages.

Siting and permitting of a new coal-based power plant in Minnesota would likely be a lengthy process. This process, along with the additional time needed to construct a coal-based facility, would push the availability of the capacity past the summer 2007 time frame needed to satisfy one of the project's primary objectives. The earliest any of the coal-based projects currently under development could be on line is 2011.

Oil Fired Simple Cycle

Description. GRE has proposed to install a simple cycle natural gas-fired system. A simple cycle system could be built to burn fuel oil instead of natural gas. In fact, the existing turbine at the Cambridge Station is a fuel oil-fired simple cycle turbine.

The simple cycle power plant is similar to the technology described for combined cycle except that the heat from the combustion turbine exhaust gases is not recovered for secondary electric generation from a steam turbine. Because of this difference, simple cycle technology has a significantly lower efficiency than combined cycle technology.

Impacts. There will be more emissions into the air from burning fuel oil than from burning natural gas. Emissions from burning the fuel will be determined by the qualities of the particular fuel oil burned.

Feasibility and Applicability. This alternative is similar to the proposed project except No. 2 fuel oil would be the primary fuel. No back-up fuel would be needed since on-site oil storage tanks would be used to provide the necessary run time. The same or largely similar units as previously described would be utilized. Because of the similarities between this alternative and the proposed project, this alternative meets the first two primary objectives for the project.

In February 2004, the Environmental Quality Board completed an Environmental Impact Statement on a proposed combined cycle natural gas plant with fuel oil backup – the Faribault Energy Park Generation Facility – in Rice County. EQB Docket No. 02-48-PPS-FEP. The reader is referred to that document for more information about air emissions related to burning fuel oil in electrical generating plants. The EIS and other documents related to that project can be found at

http://www.eqb.state.mn.us/Docket.html?Id=3217

Since the need to be near an adequate gas supply would no longer be a concern, siting this type of unit is simplified but emissions would be more of a concern. Burning fuel oil would result in higher emissions of sulfur dioxide, carbon monoxide and nitrogen oxides than a natural gas-fired alternative.

Utilizing fuel oil would result in higher operating costs compared to a natural gas-fired alternative. Higher operating costs would likely result in limiting the opportunities to provide ancillary services such as load following and regulation while operating.

Combined Cycle

Description. A combined cycle power plant is a combination of combustion turbine technology, heat recovery, and electric generation. In the combustion turbine, incoming air is compressed and mixed with the natural gas fuel. Igniting this mixture results in an expansion of gases (the combustion products and excess air) through a power turbine that in turn drives an electric generator. Hot exhaust gases exiting the combustion turbine pass through a heat recovery steam generator (HRSG) to produce steam that is used to drive a steam turbine connected to a second electric generator. Typically, of the overall electric output from a combined cycle unit, two-thirds is produced by the combustion turbine, and one-third is produced by the steam turbine generator.

Other major combined-cycle plant equipment would include:

- a system (e.g., condenser or cooling tower) to condense the steam turbine exhaust steam;
- a water treatment equipment to provide high-quality makeup water to the steam cycle;
- electrical switchgear to provide power to auxiliary plant equipment;
- water storage tanks and fuel oil storage tanks (if applicable);
- natural gas vaporizers;
- possible ammonia storage if post-combustion NOx control is required; and, operations and maintenance buildings.

Impacts. Environmental impacts for a combined-cycle project vs. a simple cycle project show distinct advantages in terms of energy efficiency (input fuel energy per kilowatt-hour produced). The energy efficiency for a combined cycle plant can be expected to be in the range of 45 to 50 percent. The direct environmental impacts of operating a combined-cycle plant burning natural gas include air emissions, wastewater discharge, waste heat discharge to air and water and the potential for on-site ammonia storage if post-combustion NOx control is required.

In February 2004, the Environmental Quality Board completed an Environmental Impact Statement on a proposed combined cycle natural gas plant – the Faribault Energy Park Generation Facility – in Rice County. EQB Docket No. 02-48-PPS-FEP. The reader is referred to that document for more information about combined cycle natural gas plants. The EIS and other documents related to that project can be found at

http://www.eqb.state.mn.us/Docket.html?Id=3217

Feasibility and Applicability. The combined cycle technology, both natural gas fired and fuel oil fired, is generally not considered for peaking service due to the relatively high capital cost when compared to simple cycle plants. Although it is more efficient to operate over longer periods than simple cycle, combined cycle technology is not as well suited to fast startup and short deployments because of the time required to bring the steam side of the plant into operation.

Combined cycle plants are well suited to meet intermediate load needs. Secondary service modes of base load and peak load are also achievable. A combined cycle plant is more economical to keep on heated standby than a coal-fired boiler would be. A combined cycle plant has a shorter construction period compared to a coal-fired plant.

Combustion turbine-based power generation can expect to reflect a planned outage rate of about 7 percent and an unplanned outage rate of about 5 percent. However, properly operated and maintained combined-cycle facilities will achieve 90 to 95 percent availability.

A combined-cycle plant can generally demonstrate high reliability. Natural gas-fired combined cycle facilities typically have fuel oil backup to address the potential interruption of natural gas supply.

The total capital requirement for a gas-fired combined-cycle power plant is estimated to be $590/kW. A typical energy cost for a gas-fired combined cycle power plant is estimated to be 4.6 cents per kW-hour.

4.5 RENEWABLE SOURCES OF ENERGY

GRE also considered possible renewable energy sources as part of its certificate of need application, including wind, biomass, ethanol-fueled, hydropower, and solar. Each of these renewable energy sources is addressed below. No specific proposals or projects have been identified.

Wind Technology

Description. Wind energy technology consists of a set of wind-driven turbine blades that turn a mechanical shaft coupled to a generator, which in turn produces electricity. The major components of the wind turbine include:

- the rotor blades;
- gear box;
- generator;
- nacelle (gearbox/generator housing); and,
- tower.

Wind turbines are either horizontal access or vertical access machines, which make full use of lift generating air flows. Each type of turbine has advantages and disadvantages. Most types are commercially available, although the horizontal access turbine is predominant. Horizontal access turbines are typically built with two or three turbine blades. Turbines for utility applications are normally installed in clusters of 5 to 50 megawatts, and may be referred to as wind farms.

GRE's wind energy is an integral part of its overall energy portfolio. Energy from the Chandler Hills Wind Farm serves the Wellspring Renewable Energy Program subscribers. In addition, GRE purchases from a wind project in Jackson County, Minnesota and from a wind project in Dodge Center, Minnesota, resulting in a total of about 18 MW of wind in GRE's current portfolio of resources.

Impacts. Wind turbine generation has many environmental advantages over fossil fuels because there are no air emissions nor solids or water discharges associated with operating the turbines. Turbines may encounter some siting opposition with regard to noise and aesthetics. In many cases, the original use of the land (i.e., agriculture) can continue in the presence of the turbine installation.

The EQB recently completed an Environmental Report on a proposed wind project – the Trimont Wind Project – for the Public Utilities Commission. PUC Docket No. IP-6339/CN-03-1841. That document and others relating to that project can be found at

http://www.eqb.state.mn.us/Docket.html?Id=5208

Feasibility and Availability. GRE eliminated wind technology from further consideration because its lack of reliability makes it unsuitable for peaking service. The reliability of a wind turbine-based generating facility depends on the wind, which is highly intermittent. The objective of the application to provide on-demand generation for peak load cannot be served by a variable energy non dispatch able resource.

Applicability for wind turbines is defined primarily by problems with reliability of the plant's "fuel", the wind. A wind turbine installation cannot adequately meet intermediate and peaking load needs. The variable nature of wind patterns does not support a strategy to address the growing demand for electric power in the near term. Siting of a large wind turbine installation is also predicated on locating candidate areas that have wind energy data that would support the project economics.

Wind turbines are generally expected to have an availability in the high 90-percent range (i.e., the turbines are capable of providing generating service). Even when wind energy is present, wind turbines can only generate power within an optimum range of wind speeds.

The total capital requirement for a wind turbine installation is estimated to be in the range of $1,000/kW. Typical energy cost for a wind turbine is estimated to be 5.4 cents per kW-hour.

Biomass

Description. Biomass encompasses a wide variety of renewable fuels. These renewable fuels may be utilized via burning in a steam cycle, gasified for use in a combustion turbine or burned directly in a combustion turbine or other internal combustion device. Solid biomass fuels include wood and waste wood, switchgrass and alfalfa stems.

GRE has significant experience with biomass resources, which aided in its analysis of whether biomass could serve its current needs. GRE operates the Elk River Station, which burns refuse-derived fuel (RDF) – material produced from processing municipal waste – to produce electricity. As a waste-to-energy power plant, Elk River Station diverts about 270,000 tons of municipal solid waste from community landfills annually.

Biomass fuels can be harvested from the forest, collected as waste materials from processing plants or agriculture, or grown in biomass plantations. Fuel may be shipped to the power plant by truck, rail or barge depending on the plant location and type. Fuel will generally be stockpiled as insurance against interruptions in supply. Depending on the fuel characteristics, drying and size reduction may be necessary prior to firing. Drying is sometimes accomplished by utilizing the heat from stack gases. Prepared fuel is fed to the furnace and the resulting heat is used to generate steam. The steam from the boiler is piped to, and drives, a steam turbine, which in turn drives an electric generator to produce saleable electrical power.

Impacts. Waste streams from the furnace include stack gases, bottom ash, and boiler water blowdown. Bottom ash produced in many biomass combustion plants is often of a quality that can be sold, or used as a soil conditioner/fertilizer due to the lack of many trace metals, which often contaminate coal ash. Boiler blowdown, along with other process wastewater streams, will typically be treated to remove solids, oils, and grease prior to discharge. Cooling water used to condense the steam exhausted from the turbine would most likely be cooled using a direct contact cooling tower. The use of a cooling tower represents a significant consumption of water.

The stack gases will contain particulate matter as well as gaseous pollutants. If a thermal drier with auxiliary firing is used, the drying step will increase energy use and environmental emissions.

Typically, stack gases will pass through an air pollution control device where particulate matter is removed. A large new boiler will likely be required to also address the control of NOx and CO emissions. Viewing environmental impacts indirectly in terms of energy efficiency (input fuel energy per kilowatt hour produced), biomass-fired plants typically operate in a range of 20 – 30 percent efficiency.

Biomass power production is affected by a greater variability in biomass fuel quality than is coal-fired power production. Variability in moisture and ash content are characteristic of a diverse fuel source and leads to variability in heat value on a mass basis. The direct environmental impacts of biomass burning are similar to those for coal combustion and include air emissions, solid waste (ash) generation, waste heat discharge to air and water, and truck and/or rail traffic.

The EQB evaluated a biomass plant in the Environmental Report on the Trimont Wind Project. The reader is referred to that document for additional information about the possible environmental effects of a biomass plant burning hybrid willows, poplars, and corn stover.

Feasibility and Applicability. A biomass facility may serve as an intermediate load unit; however, biomass-fired power boilers are best suited for base load (steady, high-capacity) duty. Stoker boilers are not well suited to operate as peaking plants because of the long lead time (a day or more) necessary to bring a solid fuel-fired plant on-line at full capacity. The forest products and agriculture industries in Minnesota offer a wide variety of available biomass fuels.

Biomass power plants are expected to have an annual outage rate for maintenance of 10 percent. Unplanned outages typically consume another 5 percent of the unit's availability. The net availability of biomass-fired units is expected to be in the range of 85 percent.

A biomass-fired plant can generally demonstrate high reliability (both the adequacy and security aspects) for base load and intermediate load service. The supply of biomass fuel in quantities sufficient to generate power at the hundred MW level and higher will require development of a fuel collection plan; however, Minnesota's agricultural and silva-cultural industries can likely support a reliable fuel supply.

The total capital requirement for a hypothetical wood burning power plant is highly variable and size dependent. Higher capacity plants will generally be much cheaper. Capital costs are estimated to be in the range of $1,100 to $1,840/kW. Typical energy cost for a wood burning power plant is estimated to be 4.9 cents per kW-hour. Building a biomass-fired power plant is a major construction project with a 24 to 36 month or longer time frame.

GRE eliminated biomass from further consideration because a biomass-fired plant cannot meet the peaking generation objectives of the project efficiently. Historically, biomass operation has not been available in sizes necessary to meet the needs of this project. Additionally, biomass generation takes long lead times to develop, has high capital cost and is most efficient in a base load application.

Ethanol-Fueled Peaking Plant

Description. Ethanol derived from corn is also considered a renewable fuel. An ethanol-fueled peaking facility would meet GRE's peaking needs. If the same equipment proposed for this project could be used for an ethanol-fired facility, the criterion of availability of 170 MW for summer 2007 could be met.

Impacts. There would be air emissions similar to natural gas and diesel fuel released from the exhaust stacks; however, due to the lack of available testing/information on firing combustion turbines with ethanol, unit output levels, emissions and construction materials would all have to be investigated further.

In general, the effects of burning ethanol in a combustion turbine are expected to include:

- Higher NOx emissions requiring the use of water injection (similar to fuel oil).
- More corrosion resistant materials required for fuel handling and storage components.
- The need to inject lubricity-improving additives.
- Maintenance costs equal to or higher than with the use of No. 2 fuel oil, which are higher than with natural gas as fuel.
- Increased ventilation and hazard detection equipment.
- Slightly higher output may be possible, but the heat rate would probably also be higher (less efficient).
- A requirement that the combustion turbine start up on natural gas, then switch to ethanol, which would require an initial investment in natural gas infrastructure to deliver the start-up fuel.

Feasibility and Applicability. The turbine manufacturers have no experience with firing ethanol in this equipment, and significant fuel storage and handling issues would arise with using ethanol as a primary fuel. In order to be accredited on ethanol, a 170-MW power plant would need approximately 400,000 gallons of ethanol stored on site.

To date combustion turbine manufacturers have not developed a combustion turbine to burn ethanol; however, they do acknowledge that it is technically possible to do so. GRE staff interviewed three major combustion turbine manufacturers regarding the prospect of developing a combustion turbine that would burn ethanol. The manufacturers indicated that they do not foresee a sufficient market to justify the research and development effort necessary to commercially develop an ethanol-fired combustion turbine. Even if GRE were willing to underwrite the costs of the effort, two of the three manufacturers indicated that they would not be able to dedicate any use of their combustion turbine testing facilities for such a purpose for two to three years because of other research and development currently underway.

The most expensive consideration of burning ethanol in a combustion turbine is the cost of the ethanol itself. GRE determined that the price of ethanol is reasonably estimated to range between $1.00 and $1.35 per gallon. Ethanol priced at $1.00 per gallon could produce electricity at a cost of $136.00 per MWh. The natural gas price would have to be as high as $12.95 per MMBtu to produce electricity at that same cost.

Hydropower

Description. Nationwide, hydropower accounts for about 97 percent of renewable generation. Hydroelectric power plants convert the potential energy of water, pooled at a higher elevation, into electricity by passing the water through a turbine and discharging it at a lower elevation. The water turns the turbine connected to an electric generator thus producing electrical energy. The turbines and generators are installed in, or adjacent to, dams, or use pipelines (called penstocks) to carry the pressurized water below the dam or diversion structure to the powerhouse. Hydropower projects are generally operated in a run-of-river, peaking, or storage mode.

Run-of-river projects use the natural flow of the river and produce relatively little change in the stream channel and streamflow. A peaking project impounds and releases water when the energy is needed. A storage project extensively impounds and stores water during high-flow periods to augment the water available during low-flow periods, allowing the flow releases and power production to be more constant. Many projects combine the modes. The capacity of a hydropower plant is primarily a function of two variables: (1) flow rate expressed in cubic feet per second (cfs); and (2) hydraulic head which is the elevation difference the water falls in passing from the reservoir through the turbine. Depending on the particular waterway being considered, project design may concentrate on either of these variables (high head/low flow or low head/high flow).

Most conventional hydropower plants include the following major components:

- Dam; controls the flow of water and increases the elevation to create the head. The reservoir that is formed is in effect stored energy.
- Penstock; carries water from the reservoir to the turbine in a power plant.
- Turbine; turned by the force of water pushing against the blades.
- Generator; connects to the turbine and rotates to produce the electrical energy.

The principal advantages of using hydropower are its large renewable domestic resource space, the absence of polluting emissions during operation, its capability in some cases to respond quickly to utility load demands, and its very low operating costs. Disadvantages can include high initial capital costs and potential site-specific and cumulative environmental impacts.

GRE eliminated hydropower from further consideration because of its long lead time. Development of hydropower potential requires a prolonged study to determine environmental and hydrologic impact. New hydropower sites will also require siting of transmission systems through remote areas, which typically require a long approval process. The current project's primary objectives include near-term capacity that hydropower cannot address because of its long development lead times.

Impacts. Hydropower projects are not sources of the typical air and water emissions and solid waste disposal issues associated with solid fuel-fired power production; however, hydropower has faced scrutiny for its significant environmental impacts (i.e., altered river basin hydrology, fish mortality, fish migration interference, decrease in water quality, and flooding of land).

Feasibility and Applicability. Hydroelectric plants are operated in several modes. Plants with large water storage capability lend themselves well to peaking power production and hydroelectric plants are able to come on line much quicker than steam generating systems. Run-of-river plants are more likely to produce a more constant power output though that output is dependent on water levels and, in cold climates, ice conditions.

The U.S. Department of Energy's (DOE) Hydropower Program has developed an estimate of undeveloped hydropower in the United States.[5] The study and its model estimate a hydroelectric potential of about 2,500 MW to be available at more than 450 potential sites located within MAPP region states. Those potential megawatts come from additional capacity at existing hydro plants (about 800 MW), from existing dams not equipped with power generating equipment (about 1,200 MW), and from sites which would require dam construction (about 400 MW).

While it is possible that some of the identified potential hydropower could be developed, exploiting the potential requiring dam construction would need to also consider that transmission systems may not exist in remote areas containing hydropower potential. Development of hydropower, and associated transmission systems, faces the scrutiny of a general environmental trend toward releasing water reservoirs where possible. Developing capacity of a hundred MW or more would require development of multiple existing and/or potential hydropower sites. Such an effort would take several years of environmental study and negotiation to acquire water use and land rights, and permits and licensing for dams and/or transmission lines.

There is potential for additional hydropower development within the MAPP region. It is unclear whether that potential can be practicably realized. The timetable to develop those resources is not likely to be able to meet near-term capacity and energy requirements.

During periods of normal precipitation and ice-free conditions, the availability of established hydropower generation is typically in the range of 95 percent.

The hydropower sector of power generation is well established with proven technologies installed as standard design. In mechanical terms, hydroelectric plants are highly reliable.

Because hydropower depends on water flow, hydroelectric plants are susceptible to fluctuations in output as a function of weather patterns. Reliability can suffer during periods of drought or during periods of freezing conditions in northern climates. Weather-induced fluctuation in power output may be less pronounced than it is for wind or solar power; however, for long-term planning to meet projected demand, hydropower may be better suited to reliably provide peak load capacity.

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[5] http://hydropower.inel.gov/techtransfer/pdfs/doe_hydropower_fy03_annual_report_final.pdf

The total capital requirement for a hypothetical hydropower power plant is estimated to be $2,000/kW. Typical energy cost for a hydropower plant is estimated to be 6.6 cents per kW hour. Most of the potential sites within MAPP have capability of less than 10 MW and economies of scale cannot be realized. Annual operating expenses would likely be less than for a fuel-fired power plant because the hydropower energy source (pooled water) is not typically a purchased input.

Building a hydroelectric power plant is a major construction project with a several-year time frame.

The construction work force is of a significant size, however, its contribution to the local economy is temporary. The long-term operation of a hydroelectric power plant would not be regarded as having a large impact on local employment rates via plant staffing. The creation of a new reservoir does have the potential for creating commerce from recreational activity if fisheries and surrounding land area are developed to attract the public.

Solar Technology

Description. Technologies for converting solar energy to electricity include thermal conversion (typically using sunlight to generate steam to turn a turbine) and photovoltaic (direct conversion of sunlight to direct current power). Thermal or concentrating solar power technology (parabolic troughs, power towers, and dish/engine systems), converts sunlight into electricity efficiently with minimal effects on the environment. Trough systems predominate among today's commercial solar-powered plants. Trough systems focus the sun at 30 to 60 times its normal intensity to heat a heat transfer fluid (synthetic oil). The hot oil is pumped to a generating station heat exchanger to produce steam. Finally, electricity is produced in conventional steam turbine generators. Trough systems may be configured as hybrids to operate on natural gas on cloudy days or after dark. Natural gas provides 25 percent of the output of the Barstow plants.[6]

The "photovoltaic effect" is the basic physical process through which a photovoltaic (PV) cell converts sunlight into electricity. Solar energy (composed of photons) is transferred to the electrons of atoms making up the PV cell. Higher energy electrons begin to flow and become electric current. By grouping single PV cells into arrays, and then placing many arrays together, power plants of up to 6.5 megawatts have been built.

Impacts. Solar power generation has many environmental advantages over fossil fuels because there are no air emissions or solids discharges associated with operating the systems. Trough/gas hybrid systems do utilize a steam loop, which requires process and cooling water, some water treatment and some wastewater discharge (blowdown).

Feasibility and Applicability. As with wind turbine generation, the applicability for solar generation is defined primarily by its fuel availability. Solar power systems generally represent even less capacity than a wind turbine installation and, combined with a dependence on

[6] http://www.sandia.gov/Renewable_Energy/solarthermal/NSTTF/question.htm

quality insolation rates, cannot meet intermediate load and peaking service needs. The variable nature of solar intensity does not support a strategy to address the growing demand for peak electric power in the near term. Siting of a large solar power plant is also predicated on locating candidate areas that have the solar energy data that would support the project economics.

Solar power plants are generally expected to have an availability in the 90-percent range (i.e., the installations are capable of providing generating service if sufficient solar energy is present).

A solar power installation cannot meet an objective of providing a guaranteed performance to the end user of generated power. The hybrid design of some solar plants, utilizing natural gas during periods of poor solar intensity, acknowledges that solar energy cannot be depended upon to maintain a capacity rating.

The total capital requirement for a photovoltaic power plant is estimated to be $4,000/kW. Typical energy cost for a hypothetical photo voltaic power plant is estimated to be 48.4 cents per kW-hour. A trough/gas hybrid plant is estimated to have a total capital requirement in the range of $3,240/kW19. Building a solar generation project, like other power projects, could utilize a significant work force for the duration of construction. Operating solar generation facilities does not require employing a large staff.

GRE Energy eliminated solar generation from further consideration because its lack of reliability makes it unsuitable for peaking service. Like wind, solar power generation has real environmental advantages; however, like wind, solar radiation is a variable energy source that is not able to meet the intent of the project to provide peaking power generation on demand. Geography also plays a role in that Minnesota is not a prime location for significant solar power generation projects. Additionally, solar technology has significantly higher costs per kilowatt to install.[7]

4.6 UP GRADING EXISTING GENERATING FACILITIES

Description. This alternative is a consideration of whether GRE could upgrade one of its existing generating facilities to provide the additional electricity that is anticipated to be needed at peak periods in the summer.

GRE has analyzed adding inlet fogging power augmentation to St. Boni. Inlet fogging is a process that adds small water droplets to the inlet air on a combustion turbine; thus, increasing the mass flow into the compressor. It is estimated that inlet fogging could add 4 to 5 MW of additional capacity at less than $100/kW of installed cost. It is likely that GRE will undertake this power upgrade after the transmission constraint outlined in Section 4.4.3 is lifted.

GRE has also considered adding wet compression power augmentation to Pleasant Valley Station units 11 and 12. Wet compression is another process where water droplets are introduced to the compressor inlets; thus, increasing mass flow by cooling the inlet air and adding water mass. It is estimated that wet compression could add 15 to 20 MW of capacity per unit. In order

[7] http://www.eere.energy.gov/solar/cs_ca_substation.html

for the upgrade project to be economical, the upgrade would have to be installed along with some other maintenance activity requiring disassembly of the compressors and turbines. This project carries additional risk because it has not been completed on any other turbines of its kind. GRE will monitor whether circumstances arise that make this project reliable and cost effective.

Finally, GRE has also analyzed adding inlet cooling and water injection power augmentation to each of its three oil-fired GE Frame 5 combustion turbines – Cambridge, Maple Lake and Rock Lake. It is estimated that such power upgrades could add 2.7 to 4.3 MW per unit. However, GRE estimates that the power upgrades to those legacy facilities would cost twice as much as adding capacity by building a new combustion turbine. Since it is not cost effective, GRE will not pursue these upgrades at this time.

Impacts. It is impossible to determine the impacts of upgrading another facility without knowing what the facility is. The actual physical construction of an expansion to an existing facility could result in environmental effects. The potential environmental impacts of operating an expanded facility have been discussed to some extent in other portions of this report through the discussion of the various alternatives that were considered.

Feasibility and Availability. GRE will continue to analyze all upgrade possibilities. At this time, none of the upgrades in progress or identified for potential future projects are appropriate to meet GRE's immediate needs.

4.7 NEW TRANSMISSION

Description. This alternative considers constructing new transmission facilities rather than new generation.

Impacts. The impacts associated with a transmission line depend to a large degree on the location of the line. Landowners whose property will be crossed by a new transmission line are often opposed to the project, particularly if the landowner perceives no personal benefit from the line.

Feasibility and Availability. Additions to or improvements in the electric transmission system are not viable alternatives to the project, primarily because new transmission lines or transmission system upgrades could not be completed in the timeframe necessary to meet the deficit forecasted for 2005.

4.8 EMERGING TECHNOLOGIES

There are a number of emerging technologies that have the potential to dramatically impact how electricity is produced, delivered and used. Many of these technologies are small enough to be located very close to the point of consumption, minimizing the need for new transmission and distribution. These technologies include:

- Fuel Cells.

- Micro Turbines.
- Energy Storage (such as batteries, pumped storage hydro, compressed air energy storage, and super conducting magnetic energy storage).

Fuel Cells: Fuel cells convert hydrogen rich fuels directly to electricity through electrochemical reactions. The reactants, fuel and oxidant (air or oxygen) are fed to separate anode and cathode electrodes. Electricity is generated by the transport of ions generated by the anode reaction across the electrolyte separating the anode and cathode. Because this is not a combustion process, there are no air emissions other than water vapor and carbon dioxide. Fuel cells are very efficient, even in small plant sizes.

Phosphoric acid fuel cells (PAFC) are currently available in 200-kW unit sizes. Their cost is in excess of $2000/kW, making them uneconomical. Molten carbonate (MCFC) and solid oxide fuel cells (SOFC) are not yet commercially available although the developers are hopeful they will become available in the next several years. Proton exchange membrane (PEM) fuel cells have created interest recently, primarily for automotive and transit applications. They are also under development for stationary power applications but are not yet commercially available.

While there is much interest in fuel cells and great expectations for commercial availability of various fuel cells, it is unreasonable to expect them to be available in sufficient quantity to meet the identified need by 2007. Most fuel cells are also baseload in nature and would not be cost effective at the low capacity factors typical of a peaking resource. Therefore, this technology will not be considered for further analysis.

Micro-turbines: Micro-turbines are small combustion turbines with capacities in the range of 30 to 250 kW. Micro-turbines are well suited for distributed generation applications. The units are small and relatively efficient for their size. Installed costs range from $450 to $700 per kW and efficiencies range from 22 percent to 30 percent. Micro-turbines for distributed generation are being developed by several potential vendors. These units have a single shaft with the generator, air compressor and turbine mounted on air bearings to eliminate the need for bearing lubrication. Power electronics convert the high frequency AC current from the generator to DC current. An inverter then converts the DC current to AC current at a standard distribution voltage. Due to the small size of the units, they can be online in a relatively short time and can be mounted on a pole, platform, in a substation, on a roof, in a vault or on a pad.

Micro-turbines are a rapidly developing technology. Although long term reliability is projected to be good, micro-turbines are not in commercial use at this time and, therefore, their reliability has not been demonstrated in real world applications. There is considerable uncertainty on the long-term O&M costs and operating life for this technology. Because micro-turbines are not commercially proven at this time, they were not selected for further evaluation.

Energy Storage: Energy storage can be used to dampen out fluctuations in the demand for electrical energy. It also allows for the possibility that electricity can be generated at low cost at times of low demand and then retrieved from storage during periods of high demand. Energy storage options include:

- Batteries; Batteries: Batteries are well known for their ability to store electrical energy. Batteries represent a resource option for electric utilities but lead acid batteries, the most common type used for storage in larger scale applications, have a limited life (1500 to 2000 charge-discharge cycles) and are expensive.
  Advanced batteries are being developed that may increase the cycle life and lower costs. As a result of the high cost of this option and limited experience in the use of batteries in utility-sized applications, this option was not considered for further evaluation.
- Pumped storage; Pumped Storage Hydro: Pumped storage hydro refers to an energy storage technology where water is pumped to a high reservoir during off-peak hours and released to generate electricity during on-peak hours. This is a mature technology. A primary problem with pumped hydro is locating suitable sites. Minnesota state law prohibits the use of the Mississippi river as a water source for pumped storage facilities. Because no suitable sites were identified, this option was not considered for further evaluation.
- Compressed air; Compressed Air: With this option, electricity is used during off-peak periods to compress air in underground caverns or porous rock reservoirs. During on-peak periods, the stored air can be released to provide compressed air for the combustion portion of a combustion turbine. This is an immature technology and existing prototype plants have not performed to expectations. Therefore compressed air was not considered for further evaluation.
- Superconducting magnets; Superconducting Magnets: A superconducting magnet refers to a coil that can store electrical energy. Because the coil is superconducting, storage losses are very low. This is an emerging technology that is not fully developed and it was not considered for further evaluation.

None of these emerging technologies are reasonable alternatives based on either the immature state of their development or their being inappropriate for peaking applications at this time.

Table 4 and **Table 5** show operational and economic comparisons between the three alternatives which passed GRE's primary screening process. These alternatives are all combustion turbine peaking plants, using three different fuel sources: natural gas (the proposed project), fuel oil and ethanol.

4.9 ALTERNATIVE SITE: ELK RIVER STATION

The Alternative Review Process (Minnesota Rules 4400.2100) does not require the applicant to propose any alternative sites; however, if the applicant has rejected an alternative site, the applicant must include in the Site Permit Application the identity of said site and provide an explanation of the reasons for rejecting the alternative site.

GRE completed a screening process that considered nine sites for the new CTG project. The initial screening analysis considered issues related to transmission, natural gas supply, land use, water availability, wastewater disposal, transportation infrastructure, local support, economics and environmental impacts. The screening process resulted in two candidate sites being considered most feasible; the Cambridge Generating Station site and the campus of GRE's headquarters in Elk River, Minnesota.

Greenfield sites and sites that would require major transmission system upgrades were not considered because of the long lead time necessary to site a new power plant and transmission line.

The Elk River site is on GRE's existing campus located within the City of Elk River in Sherburne County. The campus currently includes corporate offices, field service buildings, and the Elk River Station (a waste-to-energy generating facility).

Table 6 provides an economic comparison of the two sites for a nominal 170 MW project.

The Cambridge site was chosen after a detailed evaluation of factors such as costs, transmission requirements, natural gas supply, land use, local support, and environmental impact; the primary differentiating factor being lower overall costs.

5.0 ENVIRONMENTAL SETTING

This section contains information on the environmental setting (i.e., water resources, air quality, noise, vegetation, fish, wildlife, traffic, land use, socioeconomic factors, and cultural resources) of the proposed site area.

5.1 AIR QUALITY

The U.S. Environmental Protection Agency (EPA) and the Minnesota Pollution Control Agency (MPCA) have established ambient air quality standards for a number of common pollutants, called criteria air pollutants.[8] The criteria air pollutants are called that because they are the pollutants that are emitted in large quantities and for which health criteria existed in 1972 when Congress passed the Clean Air Act. [9] The criteria air pollutants are sulfur dioxide (SO_2), nitrogen oxides of different chemical composition (represented by the term NO_X,), particulate matter PM 10 and PM 2.5, (where the number specifies the size of the particulates in microns), carbon monoxide (CO), ozone (O_3), and lead (Pb).

A power plant of the type proposed here, burning natural gas, will emit tons of certain criteria pollutants into the atmosphere. These pollutants will be emitted out two stacks approximately 90 feet above grade and will disperse over a large area in prevailing winds. A discussion of Minnesota's air quality and various air quality indexes will help to put the impact of these additional emissions into perspective.

Air quality in the Cambridge area is similar to that of the Twin Cities in general. The air quality meets or is better than National Ambient Air Quality Standards and Minnesota Air Quality Standards for all pollutants that have promulgated standards, including sulfur dioxide, nitrogen oxide, carbon monoxide, ozone, and particulate matter. The Twin Cities is under a maintenance plan for carbon monoxide and sulfur dioxide, and the U.S. Environmental Protection Agency (EPA) recently agreed with the MPCA that the entire state, including the Twin Cities and Cambridge area, should be classified as meeting the new 8-hour ozone standard.

National Ambient Air Quality Standards (NAAQS)

The National Ambient Air Quality Standards (NAAQS) for these criteria pollutants are shown in **Table 7.**[10] The state standards are nearly identical, although Minnesota has a one-hour sulfur dioxide standard.[11] There are two types of air quality standards-primary standards and secondary standards. Primary standards are intended to protect public health, including the health of sensitive populations like asthmatics, children, and the elderly. Secondary standards are intended to protect public welfare, by preventing decreased visibility and damage to crops, animals, vegetation, and buildings.

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[8] http://www.pca.state.mn.us/air/air_rulesregs.html
[9] http://www.epa.gov/air/urbanair/6poll.html
[10] http://www.epa.gov/oar/oaqps/greenbk/index.html
[11] http://www.pca.state.mn.us/air/air_mnrules.html

Areas of the country that do not meet national ambient air quality standards are designated non-attainment areas for the particular pollutant or pollutants for which the standard or standards are not met.

Minnesota currently meets all the above standards; SO2, NO2, CO and PM10 ambient levels are less than 40 percent of their standards. Ozone and PM2.5 levels are at about 80 percent of their respective standards. Minnesota is one of only 11 states that currently meet all federal air quality standards[12]

Air Quality Index (AQI)

The Air Quality Index (AQI) was developed by the EPA to provide a simple, uniform way to report daily air quality conditions. The EPA calculates the AQI for the criteria air pollutants: ground-level ozone (O_3), particle pollution (also known as particulate matter, or $PM_{2.5}$), carbon monoxide (CO), sulfur dioxide (SO_2), and nitrogen dioxide (NO_2).

The AQI translates each pollutant measurement to a common index, with an index of 100 set to reflect where health effects might be expected in sensitive populations. An AQI value of 100 generally corresponds to the National Ambient Air Quality Standard for the pollutant, which is the level the EPA has set to protect public health.[13]

The pollutant with the highest index value is used to determine the overall AQI. The AQI uses numbers from 0 to 500 to describe the air quality conditions and their possible effects on human health. Readings of 0-50 are described as Good, 51-100 as Moderate, 101-150 as Unhealthy for Sensitive Groups, 151-200 Unhealthy, 201-300 Very Unhealthy, and 301 and above Hazardous.

In large cities (more than 350,000 people), state and local agencies are required to report the AQI to the public daily. When the AQI is above 100, agencies must also report which groups of people, such as children or people with asthma or heart disease, may be sensitive to the specific pollutant. If two or more pollutants have AQI values above 100 on a given day, agencies must report all the groups that are sensitive to those pollutants. Many smaller communities also report the AQI as a public health service.

The MPCA determines the AQI around the state by measuring four pollutants: ozone, sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$) and carbon monoxide. Not all pollutants are monitored at each location. The pollutant with the highest value determines the AQI for that hour. The MPCA takes hourly measurements of these pollutants at air quality sites located throughout the state. Ozone levels, which are only elevated in warm weather, are measured from April through September in Minnesota. While the AQI in Minnesota cities rarely reaches the "Unhealthy" level (AQI >200), many citizens are affected by air quality in the "Unhealthy for Sensitive Groups" level (AQI >100).

In 2003, the AQI reached and exceeded the minimum level for an air pollution alert (an AQI of 100-150) nine times for PM2.5 and four times for ozone. This does not mean that Minnesota

[12] Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005. MPCA
[13] Air Quality Index. A Guide to Air Quality and Your Health. August 2003. http://www.epa.gov/airnow/aqi_cl.pdf

violated federal air quality standards, however, in part because violating standards involves more than one year's data.[14]

AQI values are reported hourly on the MPCA's Web site.[15] Each weekday, you may also hear a recorded message of the daily AQI for the Twin Cities metro area by dialing 651-297-1630.

Criteria Air Pollutants

Sulfur Dioxide.

Sulfur dioxide (SO_2) belongs to the family of sulfur oxide gases (SO_x). These gases are very soluble in water. Sulfur is common in raw materials, including crude oil, coal, and ores that contain common metals like aluminum, copper, zinc, lead, and iron. SO_x gases are formed when fuel containing sulfur, such as coal and oil, is burned, and when gasoline is extracted from oil or metals are extracted from ore. SO_2 dissolves in water vapor to form sulfuric acid, and interacts with other gases and particles in the air to form sulfates and other products that can be harmful to people and the environment, including the formation of acid rain.

Sulfur dioxide causes a wide variety of health and environmental impacts because of the way it reacts with other substances in the air. Sulfur dioxide affects the respiratory system in humans, particularly those of sensitive groups like people with asthma who are active outdoors and children, the elderly, and people with heart or lung disease.[16]

Nationwide, about 20 million tons of sulfur dioxide are emitted by numerous sources each year. Over 65% of this amount, or more than 13 million tons per year, comes from electric utilities, especially those that burn coal. Other sources of SO_2 are industrial facilities that derive their products from raw materials like metallic ore, coal, and crude oil, or that burn coal or oil to produce heat for various processes.

The Minnesota Pollution Control Agency has estimated that in 2000, statewide SO_2 emissions were estimated at about 189,636 tons. Electric utilities and industrial facilities burning coal emit the majority (>85 percent) of SO_2 attributed to point sources. Within this category, electric utilities were the dominant source, accounting for about 62.3 percent of total SO_2 emissions. Ninety-nine percent of electric utility emissions are attributed to coal combustion.[17]

Off-highway vehicles and engines emit 22 percent of SO2. Off-highway emissions come primarily from non-road diesel engines and marine vessels. Highway vehicles contribute 4 percent of the emissions. These emissions are divided between gasoline-powered cars, trucks and motorcycles and diesel vehicles. The remaining three percent of area emissions of SO2 result from fuel combustion by small industrial and commercial facilities and residences.[18]

[14] Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005. MPCA
[15] http://aqi.pca.state.mn.us/hourly/
[16] How sulfur dioxides affects the way we live and breathe. 2000. US EPA Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 EPA-456/F-98-005
[17] Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005. MPCA
[18] Ibid

Nationally, SO2 emissions have decreased 31 percent over the last 20 years. Nationally and in Minnesota emissions have remained essentially level in recent years. The estimated Minnesota 2000 emissions represent a 15 percent increase from 1999 values. The increase is primarily a result of an increase in off-highway emissions from marine vessels. Estimated marine vessel emission increased from 225 tons in 1999 to 23,807 tons in 2000. Increases from this source category are surprising and likely due to a methodology change or error in the EPA inventory.[19]

Continued progress in reducing ambient SO_2 concentrations has been possible because new large utility plants have installed sulfur-removal equipment; and utility, commercial, residential and industrial users continue to shift to lower-sulfur fuels. One additional factor contributing to lower SO_2 concentrations is the lower sulfur content in today's diesel motor fuels.[20]

Nitrogen Oxides

Nitrogen oxides, or NOx, are the generic terms for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying amounts. Various compounds and derivatives make up the family of nitrogen oxides, including nitrogen dioxide ((NO_2), nitric acid (HNO3), nitrous oxide (N_2O), nitrates (NO_3), and nitric oxide (NO).[21]

Many of the nitrogen oxides are colorless and odorless. However, one common pollutant, nitrogen dioxide (NO_2), along with particles in the air, can often be seen as a reddish-brown layer (smog) over many urban areas. Nitrogen oxides also contribute to acid rain and lead to the formation of ozone upon chemical reaction with volatile organic compounds in the atmosphere.

Nitrogen oxides form when fuel is burned at high temperatures, as in a combustion turbine process. The primary sources of NOx are motor vehicles, electric utilities, and other industrial, commercial, and residential sources that burn fuels.

Nitrogen oxides cause a wide variety of health and environmental impacts and can attack the respiratory system and cause lung damage.

The EPA estimate for Minnesota statewide emissions of NOx in 2000 is 532,853 tons. The majority of NOx emissions come from the transportation sector, which consists of highway and off-highway vehicles. Highway vehicles contribute 34 percent of total statewide NOx emissions, while off-highway vehicles and engines contribute 30 percent of total NOx emissions. Gasoline and diesel engines contribute the majority of emissions from the transportation sector.[22]

Thirty-one percent of NOx emissions come from point sources as electric utilities and industrial facilities emit NOx during coal and gas combustion. Area sources are responsible for the remaining 5 percent of NOx emissions. Residential and small industrial combustion makes up the majority of area source emissions.[23]

[19] Ibid
[20] Ibid
[21] How nitrogen oxides affect the way we live and breathe 1998.US EPA Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 EPA-456/F-98-005
[22] Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005. MPCA
[23] Ibid

Background concentrations of nitrogen oxide (NO) and NO_2 are approximately 0.5 and 1 part per billion (ppb), respectively. In urban areas, one-hour average concentrations of NO may reach 1-2 parts per million (ppm), with maximum NO_2 levels of about 0.5 ppm. Atmospheric levels of NO and NO_2 show daily variations related to the human transportation/work cycle. Maximum concentrations of NO are observed in early morning hours (6 a.m. to 8 a.m.), followed by a second peak later in the day (4 p.m. to 6 p.m.). High morning concentrations of NO are followed several hours later by peak levels of NO_2 produced by oxidation of NO. Seasonal trends can also be observed. Emissions of NO increase in winter months, when there is higher consumption of heating fuel. The warm and sunny days of summer bring higher NO_2 levels, due to photochemical oxidation of NO.[24]

Nationally, NOx emissions have increased 4 percent over the last 20 years. In Minnesota, from1996-2000, NOx emissions have generally remained constant while the estimated 2000 emissions represent a 9 percent increase from 1999 values. The increase in 2000 estimated emissions is primarily a result of increased off-highway emissions including a ten-fold increase in marine vessel emissions and a doubling of emissions from railroads. Increases from these source categories are surprising and it is likely that they result from a methodology change or error in the EPA inventory. There was also an increase in residential combustion under area sources.[25]

Carbon Monoxide

Carbon monoxide, or CO, is a colorless, odorless gas that is formed when carbon rich fuel is incompletely combusted.

The EPA estimate for Minnesota statewide emissions of CO in 2000 is 2,104,632 tons. The majority of CO emissions come from the transportation sector, which consists of highway and off-highway vehicles. Highway vehicles contribute 52 percent of total statewide CO emissions, while off-highway vehicles and engines contribute 32 percent of total CO emissions. Off-highway emissions come primarily from gasoline consumption by lawn and garden, industrial and recreational engines. The remaining 16 percent of emissions come from point and area sources. Area source emissions are primarily from residential wood burning, waste disposal through open burning and other combustion sources such as wildfires. Point sources include electric utilities and other industries that contribute to CO emissions through fuel combustion. Petroleum refineries are the primary industrial point source that contributes to CO emissions.[26]

Nationally, CO emissions have decreased 18 percent over the last 20 years. However, in Minnesota from1996-2000, CO emissions have generally remained constant except for the estimated 2000 emissions, which represent a 15 percent increase from 1999 values. The EPA inventory attributes this increase to an increase in residential wood burning, non-highway gasoline engine emissions and miscellaneous combustion including wildfires. It is unlikely that actual emissions increased this much over one year, based on trends from years past.[27]

[24] http://www.pca.state.mn.us/air/emissions/emissearch.cfm
[25] Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005. MPCA
[26] How carbon monoxides affects the way we live and breathe. 2000. US EPA Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 EPA-456/F-98-005
[27] http://www.pca.state.mn.us/air/emissions/emissearch.cfm

Particulate Matter

Particulate matter, or PM, is the term used to describe particles found in the air (dust, soot, smoke, and liquid droplets). Particles can be suspended in the air for long periods of time. Some particles are large or dark enough to be seen as soot or smoke, while others are microscopic. The larger groups of particles are identified as "coarse," and by definition have a size range from 2.5 to 10 microns (PM_{10}). The smaller groups of particles are identified as "fine," and by definition have a size smaller than 2.5 microns ($PM_{2.5}$). For comparison, a human hair is usually greater than 10 microns in thickness, in the range of 10 to 100 microns.

Particulate matter can be directly emitted into the air or be formed in the air from the physical and chemical transformation of other vaporous or gaseous pollutants such as NO_X, SO_X, VOC and ammonia. The latter are indirectly formed when gases from burning fuels react with sunlight and water vapor. These can result from fuel combustion in motor vehicles, power plants, and in industrial processes.

Particulate matter causes a wide variety of health and environmental impacts. Many scientific studies have linked breathing PM to a series of significant health problems, including cardiovascular problems, throat and nose irritation, lung damage, and bronchitis.[28]

The EPA estimate for Minnesota statewide direct emissions of PM_{10} in 2000 is 894,093 tons. Emissions of secondarily formed PM_{10} are not accounted for in these emissions.[29]

Area sources contribute 92 percent of PM_{10} emissions. The area sources consist of fugitive dust (63 percent) and agriculture and forestry (33 percent) according to the EPA inventory. The remainder of the area source contribution is from combustion. Fugitive dust sources include unpaved roads, paved roads, construction and other sources.

Industrial sources including metal processing, storage and transport, electric utilities, and other industrial processing account for 6 percent of PM_{10} emissions. Metal processing accounts for 45 percent of the industrial portion of PM_{10}. Highway and off-highway sources make up about 2 percent of total PM_{10}.

Fugitive dust sources tend to be located away from people and tend to be coarser particles, which are of less concern from a human health perspective. Particles emitted from non-fugitive dust sources such as cars and wood stoves are smaller, more toxic and more often released in populated areas.

In the 1970's the ambient air quality standard for particulate matter applied to particles larger than 10 microns. In 1997, however, the EPA announced new standards for the smaller (fine) particles, those 2.5 microns or less in diameter ($PM_{2.5}$). The new ambient standards were set at 15 micrograms per cubic meter (ug/m^3) on an annual basis and 65 ug/m^3 for a 24-hour period. Evidence from hundreds of studies has shown that these tiny particles are chiefly responsible for the most serious adverse health impacts associated with air pollution. When inhaled, $PM_{2.5}$

[28] How particulate matter affects the way we live and breathe. 2000. US EPA Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 EPA-456/F-98-005
[29] Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005. MPCA

penetrates deep into the human lung, where the particles and the toxic materials attached to them remain lodged.[30]

Nationally, manmade direct PM_{10} emissions have decreased 47 percent over the last 20 years. In Minnesota direct emissions have oscillated up and down from 1996-2000. The estimated Minnesota 2000 emissions represent a 5.5 percent increase from 1999 values. The increase is primarily a result of increased residential wood burning, agricultural and forestry, fugitive dust, and an increase in miscellaneous combustion including wildfires.[31]

Nationally, manmade direct $PM_{2.5}$ emissions have decreased 5 percent over the last 10 years. The estimated Minnesota 2000 emissions (191,198 tons) represent a 10 percent increase from 1999 values (211,389 tons).[32]

Monitored annually for the past three years to determine whether Minnesota attains the NAAQS, average concentrations of fine particulates in the Twin Cities typically range from 11 ug/m^3 to 14 ug/m^3. Atmospheric $PM_{2.5}$ reached alert levels twice in 2002 in Minnesota.[33]

Ozone

Ozone (O_3) is a gas composed of three oxygen atoms. Ozone naturally exists high in the atmosphere, where it shields the earth against harmful ultraviolet rays from the sun. Ground-level (i.e., near the earth's surface) ozone is a product of reactions between oxides of nitrogen (NO_x) and volatile organic compounds (VOC) in the presence of heat and sunlight. Ozone has the same chemical structure whether it occurs miles above the earth or at ground level; its location in the atmosphere determines whether it represents a problem. In the earth's lower atmosphere, at ground-level, ozone is considered harmful. Sunlight and hot weather cause ground-level ozone to form in harmful concentrations in the air. As a result, it is known as a summertime air pollutant. Many urban areas tend to have high levels of ground-level ozone, but even rural areas are also subject to increased ozone levels because wind carries ozone and pollutants that form it hundreds of miles away from their original sources. Ground-level ozone even at low levels can adversely affect everyone. It can also have detrimental effects on plants and ecosystems.[34]

Ozone can cause breathing problems in sensitive populations. It can also damage plants and trees. Ozone can also reduce visibility.

In late June 2001, the Air Quality Index (AQI) for the Twin Cities reached some of its highest levels since the Clean Air Act took effect in the 1970s. On four days the AQI reached a level considered unhealthy for sensitive groups. These high AQI readings were primarily a result of elevated ground-level ozone concentrations.

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[30] *Reanalysis of the Harvard Six Cities Study and the American Cancer Society Study of Particulate Air Pollution and Mortality.* A Special Report of the Institute's Particle Epidemiology Reanalysis Project. July 2000. http://www.healtheffects.org/pubs-special.htm
[31] Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005. MPCA
[32] Ibid
[33] Minnesota Energy Planning Report 2002. Appendix A
[34] How ground-level ozone affects the way we live and breathe. 2000. US EPA Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 EPA-456/F-98-005

Emissions of ozone are not reported because ozone is not normally emitted directly into the air. Instead, it is created when "ozone precursors" such as nitrogen dioxide (NO_2) and volatile organic compounds (VOCs) react in a hot stagnant atmosphere. Since heat and sunlight are needed for ozone to be produced, elevated levels of ozone in Minnesota are normally seen on very hot summer afternoons.

Ozone precursors come from a variety of sources. NO_2 can form when fuels are burned at high temperatures. The major NO_2 sources are combustion processes from automobiles and power plants. VOCs are emitted from a variety of sources, including industrial sources, motor vehicles, consumer products and natural sources such as lightning and biological processes in soil.[35]

Lead

Lead levels in the environment have decreased dramatically since lead in gasoline was banned by the Environmental Protection Agency in 1978. The only places where lead is still found in concentrations of concern is in the inner cities, where years of exhaust from motor vehicles burning leaded gasoline have resulted in high levels in the soil in such areas.

In Minnesota, lead in the air has dropped significantly. Between 1984 and 1994 average lead concentrations decreased 87% from .53 micrograms per cubic meter (ug/m3) to 0.06 ug/m3. The national ambient air quality standard is 1.5 ug/m3.[36]

Volatile Organic Compounds

Volatile organic compounds (VOCs) are compounds containing the elements carbon and hydrogen that exist in the atmosphere primarily as gases because of their low vapor pressure. VOCs are defined in federal rules as chemicals that participate in forming ozone. Therefore, only gaseous hydrocarbons that are photochemically reactive and participate in the chemical and physical atmospheric reactions that form ozone and other photochemical oxidants are considered VOCs.

Many VOCs are also air toxics and can have harmful effects on human health and the environment. However, VOCs are regulated as a criteria pollutant because they are precursors to ozone.

The EPA estimate for Minnesota statewide emissions of VOCs in 2000 is 458,306 tons. VOCs are emitted from a variety of sources, including industrial sources, motor vehicles, consumer products and natural sources such as lightning and biological processes in soil. Of the manmade Minnesota sources of VOCs in 2000, 50 percent of the emissions come from the transportation sector; 24 percent from highway vehicles and 26 percent from off-highway vehicles.[37]

[35] Preliminary Assessment of Ozone Air Quality Issues in the Minneapolis/St. Paul Region. Sonoma Technology, Inc. October 10, 2002. http://www.pca.state.mn.us/publications/reports/ozonestudy2002.pdf
[36] Air Quality in Minnesota Progress and Priorities, 2005 Report to the Legislature. February 2005. MPCA
[37] Ibid

Area sources contribute 42 percent of VOC emissions, primarily from solvent utilization, residential wood combustion, and storage and transport of fuels and chemicals. The final 8 percent of emissions come from point sources.

Greenhouse Gases

Another group of air pollutants has risen in importance. Although greenhouse gases (GHG) do not necessarily directly harm human health, their increase in concentration can lead to global climate change. Global climate change poses risks to human health and to ecosystems. Important economic resources such as agriculture, forestry, fisheries, and water resources also may be affected. The principal GHG is carbon dioxide (CO_2).

The estimate for statewide emissions of carbon dioxide, from the fossil fuel burning, in 2000 is 109 million short tons. The majority of the carbon dioxide emissions come from the electric utility (36%) and transportation (34%) sectors. The remaining 30 percent of the emissions come from fossil fuel combustion in the industrial, commercial, residential and agriculture sectors.[38]

Over the five years from 1996-2000, carbon dioxide emissions from fossil fuel burning in Minnesota rose an average of 1.2 percent per year. These increases reflect a continuing increase in the electric utility and transportation sectors. From 1999 to 2000, carbon dioxide emissions increased 5.6 percent.[39]

Toxic Air Pollutants

The burning of natural gas and fuel oil can also result in the emission of non-criteria pollutants of concern. EPA refers to certain chemicals that cause health and environmental hazards as "hazardous air pollutants (HAPs)" or "air toxics." Air toxics include chemicals such as benzene, formaldehyde, acrolein, mercury and polycyclic aromatic hydrocarbons (PAHs). EPA tracks emissions of these chemicals in the National Toxics Inventory (NTI) database.[40]

The MPCA compares concentrations of air toxics in the ambient air to inhalation health benchmarks to determine at what concentrations toxics may cause health concerns. An "inhalation health benchmark" is a point or range below which there is little appreciable risk of harm to humans. Unlike the federal ambient air quality standards, they are guidelines rather than enforceable regulatory standards.

Out of the 45 gaseous air toxics measured by the MPCA that have health benchmarks, the 2003 air quality legislative report identified two that were above health benchmarks: benzene and formaldehyde. Benzene concentrations have been declining since 1996 and current levels are now below inhalation health benchmarks.

Measurements of formaldehyde are above its inhalation health benchmark in Minneapolis, St. Paul, and Duluth, as well as in most other Minnesota cities with monitors. Formaldehyde

[38] Ibid
[39] Ibid
[40] http://www.epa.gov/ttn/atw/

concentrations in Minnesota have been relatively flat since 1995. However, the last two years have shown decreasing levels, especially in downtown Minneapolis. More monitoring is needed to see if this trend continues.

Formaldehyde comes from a variety of sources. It is directly emitted from wood-burning and from fuel-burning vehicles, as well as industrial processes. A significant amount of formaldehyde also comes from the breakdown of other air toxics and from natural sources. These disparate sources make it difficult to control formaldehyde emissions.

5.2 LAND USE

The new generating unit will be located within the footprint of an existing plant in an industrial-zoned area and will not change the land use of the area. The area surrounding the Cambridge Station is zoned by Isanti County as Agricultural District (A). A zoning map of the area is shown in **Figure 9**.

The nearest residence is located approximately 1,300 feet southwest of the proposed CTG position.

The addition of the CTG at the Cambridge Station will not require the displacement of any occupied residences or businesses. Work on the Cambridge Station will not displace any other existing or planned land use, including residential land uses. The proposed site for the new generating unit is located within a parcel currently owned by GRE and used for power generation (**Figure 10**).

5.3 NATURAL RESOURCES

The Ecological Classification and Inventory (EC&I) is part of a nationwide mapping initiative, initially established by the US Forest Service, developed to improve the ability to manage natural resources on a sustainable basis. The central concept of the EC&I is the integration of biotic and abiotic environments. This method of classification not only facilitates understanding of the natural environment and the distribution of complex ecological systems, but also allows aggregation and desegregation of data and information for multi-level analysis and planning purposes. This is done by integrating climatic, geologic, hydrologic, topographic, soil, and vegetation data. Three of North America's ecological regions, or biomes, converge in Minnesota: prairie parkland, eastern broadleaf forest and laurentian mixed forest. The occurrence of three biomes in one non mountainous state is rare, and accounts for the diversity of ecological communities in Minnesota.[41] The eastern broadleaf forest province bridges the transition zone between prairie to the west and true forest to the east.

The eastern broadleaf forest province has several subsections; the proposed site lies within the Anoka Sand Plains subsection of this province. The major landform is a broad sandy lake plain,

[41] Albert, Dennis A. 1995. Regional landscape ecosystems of Michigan, Minnesota, and Wisconsin: a working map and classification. Gen. Tech. Rep. NC-178. St. Paul, MN: U.S. Department of Agriculture. Forest Service, North Central Forest Experiment Station.

which contains small dunes, kettle lakes, and tunnel valleys. Topography is level to gently rolling. There are small inclusions of ground moraine and end moraine.

Topography/Landform

The landscape of Isanti County is dominated by glacial and post-glacial deposits. The landscape is characterized by undulating and rolling morainic hills, outwash sand plains, old glacial lake beds, and numerous bogs, lakes, dry stream channels, and barbed streams. There are no exposures of bedrock.[42]

There are two types of glacial drift deposits in the county. The older is the middle Wisconsin drift, commonly called red drift because of the color of the unweathered material. The drift material was transported from the region around Lake Superior and Duluth by a glacier that advanced from the northeast. Red drift is stony, generally coarse textured, and low in lime.[43]

The later drift was deposited by the Grantsburg sublobe of the Des Moines lobe, which advanced from the northwest during the late Wisconsin glacial age. The material is gray when unweathered, and the deposits are commonly termed gray drift. Gray drift was derived from limestone and calcareous shale; it is less stony than red drift and is relatively fine textured.[44]

Several belts of morainic hills, formed from material deposited during one of the earlier glacial periods, extend across the county; areas of rolling topography occur in Cambridge Township. The elevation of the proposed site is approximately 950 feet mean sea level (msl).

Geology/Soils/Hydrology

The Cambridge Station site is located within the Anoka Sand Plain region and is underlain by approximately 100 feet of unconsolidated sediments, according to regional well logs[45].

Pleistocene-aged lake sediments associated with the Grantsburg sublobe of the Des Moines lobe are directly beneath the site. These lake sediments consist primarily of very fine to medium sand with minor amounts of silt. Till deposits associated with the Grantsburg sublobe and recent alluvium and organic deposits occur elsewhere in the region. The unconsolidated sediments found on the Cambridge Station site are underlain by Cambrian-aged sedimentary rocks. **Figure 11** illustrates the surficial geology of the site.

The Soil Survey of Isanti County, Minnesota (1958) indicates soils found on the site are Anoka and Lino loamy fine sands. The Lino and Anoka series are nearly level to gently sloping and formed in outwash sands. Soils can be poorly drained due to the profile of loamy sand over fine sands (**Figure 12**). Since the Cambridge Station site has been in an industrial land use, the soils have been altered due to prior construction activities.

[42] R. S. Farnham, Soil Survey Isanti County. September 1958.
[43] Ibid
[44] Ibid
[45] County Well Index, Minnesota Geological Survey (MGS) and the Minnesota Department of Health (MDH)

Few natural streams have developed in Isanti County; nearly the entire county is drained by the Rum River. The Rum River enters Isanti County from the west and flows eastward to a point about 3 miles north of Cambridge and then southward into western Anoka County, where it joins the Mississippi River.

The Cambridge Station site is located within the Rum River watershed. The nearest named stream is Beckins Creek, branches of which are approximately 1,300 feet north, 1,000 feet south, and 2,200 feet west of the site. The Rum River is approximately one mile west of the Cambridge Station site. The nearest lake, Rum Lake is approximately 3,700 feet east of the Cambridge Station site (**Figure 13**).

Surface water runoff from the south portion of the site will be routed to an on-site retention basin, while discharge from other portions of the site will follow existing drainage patterns. Process wastewater, primarily evaporative cooler blow down wastewater, will also be discharged to the retention basin. Combined storm water and process wastewater will be discharged from the retention basin to a wetland south of the site. The wetland drains to the southwest, eventually into Beckins Creek and ultimately to the Rum River.

The existing transmission lines to be upgraded cross a number of public waters and wetlands, but most are spanned and in other locations any disturbance for the rebuilds will be minimal and limited to pole placement. The MDNR identified three locations of special concern related to water resources. The Cambridge to East Bethel transmission line passes through Cedar Creek Natural History Area, which contains wet meadow, alder swamp, white cedar swamp, tamarack swamp, mixed hardwood swamp, rich fen, and cattail marsh native plant communities. The Cambridge to Grasston transmission line crosses the Snake River in Grasston (T38N R23W Section 13) and passes through a "Site of Moderate Biodiversity Significance" (T37N, R23W, Section 2). GRE will comply with the recommendations made by the MDNR to mitigate and minimize impacts in these sensitive areas.

Wetlands

No wetlands are located within the Cambridge Station site. There are several wetlands found in the area surrounding the plant site, the nearest of which is a saturated forested wetland approximately 250 feet west of the site. The proposed Cambridge Station will discharge combined storm water and process wastewater from an on-site retention basin to a wetland located about 300 feet south of the site. There are two additional wetlands located with 1,000 feet of the Cambridge Station site (**Figure 14**). **Table 8** lists the Cowardin classification for all wetlands within approximately 2,000 feet of the Cambridge Station site.

Flora

The Cambridge Station site is located on the Anoka Sandplain landform, with pre-settlement vegetation being primarily composed of oak openings and barrens (savanna) on the upland areas and river bottom forest adjacent to the Rum River at lower elevations. Most of the native vegetation has been removed to allow the land to be converted to agricultural uses. There are some remnants of pre-settlement vegetation indicated by the Minnesota County Biological

Survey (MCBS) to the west across the railroad tracks and Highway 65 known as the North Cambridge Swamp (**Figure 15**). The MCBS data identifies minerotrophic tamarack swamp (*Larix larcina*) and mixed hardwood swamp as native plants communities located approximately 1,000 feet west and northwest of the site. MCBS survey data also identify a small area of mesic oak forest adjacent to the swamps on the upland areas.

The transmissions lines to be upgraded cross or are immediately adjacent to a number of sites identified by the MDNR. Ninety-four occurrences were listed in the MDNR Natural Heritage Inventory System (NHIS) database within a one-mile radius of the transmission lines and the Cambridge Station site. Six locations of special concern were identified by the DNR.

A site of outstanding biodiversity significance is located just east of the transmission line north of East Bethel (T34NR23W Sections 16 and 21). This particular site is the Cedar Creek Natural History Area, contains wet meadow, alder swamp, white cedar swamp, oak forest, white pine forest, tamarack swamp, mixed hardwood swamp, rich fen, and cattail marsh native plant communities, and provides habitat for several rare plant and animal species.

Several sites of biodiversity significance are located adjacent to the Cambridge to Rush City transmission line in T37N R22W Sections 26 & 36 and T37N R21W Section 30. The Cambridge to Grasston transmission line passes through a site of moderate biodiversity significance west of Braham (T37N R23W Section 2). This site contains Tamarack Swamp and Poor Fen native plant communities.

Fauna

The MDNR Natural Heritage Program was contacted by Barr Engineering to review their NHIS database (**Appendix B**). Results of the database search identified Blanding's turtle as being present in the vicinity of the Cambridge Station site, but not on the site. Construction activities should not adversely impact any Blanding's turtle habitat given the agriculture land use that abuts the property.

Blanding's Turtles (*Emydoidea blandingii*), a state-listed threatened species, have been reported in the vicinity of all three transmission lines by the DNR. The DNR have provided recommendations to prevent harm to turtles during construction work that will be followed during the upgrade construction activities. The Cambridge to Grasston transmission line crosses the Snake River immediately south of Grasston (T38N R23W Section 13). Several rare freshwater mussel species including Mucket, Purple Wartyback, and Round Pigtoe Mussels (threatened species) and Spike, Black Sandshell, Fluted-Shell, Creek Heelsplitter, and Hickorynut Mussels (special concern species) have been documented in the Snake River in this vicinity. Erosion and sediment control practices implemented and maintained during any line rebuilding will prevent impacts to mussel populations.

Rare & Unique Natural Resources

Staff of the Natural Heritage Program of the MDNR was contacted by Barr Engineering and asked to review its database to determine if any rare plant or animal species or other significant natural features are known to occur within the site.

No plants or animals of concern were listed for the Cambridge Station site.

Ninety-four occurrences were listed in the MDNR NHIS database within a one-mile radius of the transmission lines and project site. The six locations of special concern were identified by the MDNR as discussed previously.

Recreation Areas

No recreational areas have been identified on or within the immediate vicinity of the site (**Figure 16**).

5.4 VISUAL AESTHETIC

The proposed plant site is already developed and includes the existing power plant and its 25-MW fuel oil-fired CTG. The new gas-fired plant will be larger than the existing fuel oil-fired plant, and two new water tanks will constructed. The new Cambridge Station will result in a similar industrial look as the existing plant.

The project will also include upgrading approximately 47 miles of 69-kV transmission line in Isanti, Chisago and Kanabec counties to improve the overall operation and reliability of the Cambridge area transmission system. The transmission line rebuilds will involve changing to taller poles (from approximately 40-55 feet to 60-65 feet above ground), upgrading wire size, and adding lightning protection. The transmission lines will not appear significantly different than the existing transmission line configurations.

Figure 17 illustrates an artist rendition of how the Cambridge Station will appear on the landscape.

5.5 ARCHAEOLOGICAL and HISTORIC RESOURCES

The Cambridge Station will be limited to the previously industrial site, thus there will be no direct impacts to any buildings, including historic structures.

The Cambridge Station project will also include upgrading approximately 47 miles of 69-kV transmission line in Isanti, Chisago and Kanabec counties to improve the overall operation and reliability of the Cambridge area transmission system. The Minnesota State Historic Preservation Office (SHPO) has been asked by Barr Engineering to review their records to determine whether there are any reported historic or archaeological resources in the vicinity of the project site. Their review response and the listing of recorded archaeological sites and historical resources within a one mile distance of the project site and transmission lines is included in **Appendix B**. The results of the Minnesota Historical Society (MHS) database search request indicated that 15 recorded archaeological sites and five national register properties are located within one mile of the Cambridge Station site and/or transmission lines. Barr Engineering sent a letter to the MHS requesting an assessment of the Cambridge Station project's potential to impact these sites or properties. That letter and the MHS response, where the MHS concluded no properties eligible for or listed on the National Register of Historic Places are within the area of effect, are included in **Appendix B**.

5.6 TRANSPORTATION

The major traffic routes in the vicinity of the Cambridge Station are Minnesota Highway 65, which runs north and south west of the Cambridge Station, and Minnesota Highway 95, which runs east and west approximately two miles south of the plant site (**Figure 18**).

The Burlington Northern Santa Fe Railway track passes directly adjacent to the west portion of the site (**Figure 18**). Construction of the plant and transmission line upgrades will not impact area airports (see MDOT correspondence in **Appendix B**).

Additional traffic generated by the proposed Cambridge Station project is limited to the truck traffic associated with construction in the short-term and GRE operation and maintenance staff in the long-term.

5.7 SOCIOECONOMICS

Socioeconomics refers to the economic, social, and demographic characteristics of a region. The existing socioeconomic characteristics of Isnati County, the State of Minnesota, and the Twin Cities Metropolitan area were reviewed by the EQB staff.

Isanti County comprises a land area of 282,880 acres in the east central portion of Minnesota. Cambridge, the county seat, is situated along the Rum River, slightly east of the center of the county. The county is 40 miles north of St. Paul, 100 miles southwest of Duluth, and 45 miles east of St. Cloud. The county is 24 miles across at the southern border and 18 miles across at the northern border, and extends 22 miles from north to south. The 2000 census reports Isanti County's population at 31,287 and the City of Cambridge with a population of 5,520.[46]

Table 9 presents the recent population figures for Isanti County, Cambridge and the State of Minnesota.

The Cambridge Station site will be surrounded by an 8-foot high, chain-link fence. Access into the site will be controlled by an automatic gate with the option for manual operations from the Control Room and GRE's 24-hour System Operations Center in Elk River, Minnesota. The site will be monitored through closed circuit television linked to the control room and the System

[46] Minnesota Planning Agency, State Demographic Center (http://www.mnplan.state.mn.us/demography/index.html)

Operations Center. GRE will work with local law enforcement agencies to provide reliable security.

5.8 NOISE

Noise is comprised of a variety of sounds, of different intensities, across the entire frequency spectrum. Humans perceive sound when sound pressure waves encounter the auditory components in the ear. These components convert the pressure waves into perceivable sound. Noise is measured in decibels (dB).

Noise standards have been established by the MPCA, Minnesota Rules part 7030.0040, subp. 2. The MPCA is the regulatory agency responsible for the enforcement of these standards. The standards are consistent with speech (hearing and conversation), annoyance, and sleep requirements for receivers within areas classified according to land use activities.

The MPCA has established various noise area classifications (NAC) and has established noise standards for each classification. The NAC is based on the land use activity at the location of the receiver, and the NAC determines the applicable noise standard. Lower noise levels are required in residential areas, for example, than in industrial zones.

The four noise area classifications are: NAC-1, NAC-2, NAC-3, and NAC-4. Some of the land use activities under NAC-1 include household units, hospitals, religious services, correctional institutions, and entertainment assemblies. NAC-2 land use activities include mass transit terminals, retail trade, and automobile parking. Some NAC-3 land uses include manufacturing facilities, utilities, and highway and street ROW. NAC-4, which has no noise limits, consists of undeveloped and under construction land use areas.[47]

Table 10 sets forth the Minnesota Noise Standards for the appropriate land use areas.

Noise area classifications apply at the location of the noise receptor, not at the property boundary of the noise source. Further, the noise rules require that a municipality with authority to regulate land use prevent new land uses defined in the NAC categories from being established where the noise standards shown in Table 4 would be exceeded if the new land use is permitted.

GRE contracted HDR Engineering, Inc. to conduct noise level monitoring at the fence line around the site and south-southwest of the site near the intersection of Main Street and Township Road 75. Measurements were taken during daytime hours to determine background levels and levels from the existing Frame 5 combustion turbine at the site.

Background noise around the site appears to be predominantly associated with traffic on Highway 65 and Main Street. Background L50 noise levels (the 50th percentile level for the period of time measured) at the fence line ranged between 49 and 52 dBA. The background L50 level south-southwest of the site was 52 dBA.

[47] http://www.pca.state.mn.us/programs/noise.html

With the existing Frame 5 combustion turbine in operation, L50 levels at the fence ranged between 56 and 63 dBA. At the south-southwest monitoring location, the L50 level was 56 dBA.

The locations of the two residences closest to the proposed CTG location are highlighted on **Figure 2**.

6.0 HUMAN & ENVIRONMENTAL IMPACTS

This section contains site specific information on the human and environmental impacts of the proposed large electric power generating plant. The impacts evaluated include those resulting from construction and operation of the plant and include potential impacts of the proposed plant on water resources, air quality, noise, vegetation, fish, wildlife, traffic, land use, socioeconomic factors, and cultural resources.

6.1 AIR QUALITY

The Cambridge Station proposed project is a new combustion source and will emit products of combustion to the air. The new combustion turbine will use clean-burning natural gas combustion technology, dry low-NO_X emissions control technology, and will have limits on the total amount of emissions.

GRE plans to submit an application for an amendment to the existing Cambridge Generating Plant air emission permit, Permit No. 05900014-001, to the Minnesota Pollution Control Agency in late spring 2005. The permit application requests that emissions from the plant, after the additional of the natural gas-fired CTG, be limited to less than 250 tons per year (tpy) of NOx, CO, SO_2, or PM_{10}. This will effectively limit operation of the natural gas-fired CTG to about 3,000 hours per year. The actual hours of operation will depend on the equipment manufacturer chosen, the time of year that the unit is operated, and the actual generating rate at which the unit is operated.

Criteria Air Pollutant Emissions

The estimated actual air emissions from the new units, based on expected operating hours are presented in **Table 11**. These emission estimates are based on the new unit operating for 876 hours a year (a 10 percent capacity factor), which is about a third of the operating hours that the anticipated air permit conditions would allow. Should the CTG operate more frequently than anticipated, actual emissions could be up to approximately three times those presented in Table 11.

NAAQS Modeling

As part of the PSD permit application, air-dispersion modeling was performed to demonstrate that the emissions from the facility will not cause or contribute to a violation of an ambient air quality standard or PSD increment. Modeling was performed using a modeling protocol (ISC3-Prime) that conforms to U.S. Environmental Protection Agency (EPA) standards to predict the maximum ambient concentrations.

The results of the modeling, presented in **Table 12**, indicate that the Cambridge Station will have a minimal impact on area air quality for all pollutants modeled. The modeled concentrations are well below National Ambient Air Quality Standards and Minnesota Air Quality Standards for all pollutants.

Hazardous Air Pollutants

In addition to criteria pollutants, the proposed facility will generate small amounts of hazardous air pollutants (HAPs). The EPA has developed National Emission Standards for hazardous air pollutants (i.e., NESHAP) for numerous source categories.

The Clean Air Act Amendments of 1990 established a new and fairly complex program to regulate emissions of 188 hazardous air pollutants from particular industrial sources. The amendments required the EPA to regulate emissions of these HAPs by developing and promulgating technology-based standards. New sources are subject to these requirements if they have the potential to emit HAPs in "major" amounts (i.e., 10 tons or more of an individual pollutant or 25 tons or more of a combination of pollutants).

Estimates of potential HAP emissions are also presented in **Table 11**.

Air Emission Risk Analysis

The new CTG at the Cambridge Station is exempt from the requirement to conduct an Air Emissions Risk Analysis (AERA) in accordance with MPCA technical guidance (Air Emissions Risk Analysis Guidance; Version 1.0; March 2004). The purpose of the AERA is to assess the potential health risk attributed to air emissions from a given source. MPCA guidance exempts natural gas-fired combustion units from review.

Other Sources of Air Pollution

Another potential source of air emissions is fugitive dust from site preparation and construction activities. Fugitive emissions will be controlled to reduce their impact on area residents by watering or applying dust suppressants to exposed soil surfaces as necessary.

6.2 LAND USE

As described in Section 5.2, the new generating units will be located within the footprint of an existing plant in an industrial-zoned area and will not change the land use of the area.

Zoning and Displacement

The Cambridge Station project will not require the displacement of any occupied residences or businesses. Work on the project will not displace any other existing or planned land use, including residential land uses. The proposed site for the new generating unit is located within a parcel currently owned by GRE and used for power generation (**Figure 2**). The nearest residence is located approximately 1,300 feet southwest of the proposed CTG location.

Agriculture and Farmland

No prime farmland will be taken out of production.

6.3 NATURAL RESOURCES

Flora

As identified in Section 4.3, there are some remnants of pre-settlement oak and barrens vegetation located to the west of the Cambridge Station site. Because of their location on the opposite side of the railroad tracks and Highway 65, these remnants will not be negatively impacted by construction activities.

Fauna

The addition of the natural gas CTG is not expected to negatively impact wildlife in the area

Rare & Unique Natural Resources

No plants or animals of concern were identified that would be adversely impacted by the proposed project.

Recreation Areas

No tourism or recreation areas will be adversely impacted by the construction and/or operation of the proposed Cambridge Station project.

Prohibited Sites

The EQB has identified (Minnesota Rules part 4400.3450) certain areas, termed "Prohibited Sites", in which no LEPGP can be sited. Examples of prohibited sites include national parks, national historic sites and landmarks, state parks, nature conservancy preserves, and state and national wilderness areas. No prohibited sites are found on or in the immediate vicinity of the proposed site.

Forestry

No forestry-related industry will be adversely impacted by the construction and/or operation of the proposed Cambridge Station.

Mining

No mining-related industry will be adversely impacted by the construction and/or operation of the proposed Cambridge Station.

6.4 VISUAL AESTHETICS

Area aesthetics will not be significantly changed by the proposed Cambridge Station project. The proposed plant site is already developed and includes the existing Cambridge Station and its

25-MW fuel oil-fired CTG. The new gas-fired plant will be larger than the existing fuel oil-fired plant, and two new water tanks will constructed.

The proposed Cambridge Station project will result in a similar industrial look as the existing plant.

Exterior lighting for the facility will be provided as required for security and safety throughout the facility. Illumination levels will be in accordance with the Illuminating Engineering Society (IES) Handbook and code requirements.[48] To reduce the visibility of the facility, task lighting will be utilized instead of flood or area lighting. Lights will be shielded and/or directed towards the ground as much as practical.

6.5 ARCHAEOLOGICAL & HISTORIC RESOURCES

The proposed Cambridge Station project will have no adverse effect on the historical properties in the vicinity of the site.

6.6 TRANSPORTATION

The additional traffic will not significantly affect area transportation services.

6.7 SOCIOECONOMICS

The local community will benefit from the construction of the proposed Cambridge Station project. Construction will require an estimated 100 skilled craft workers over the 12-month construction period. These high-skill, high paying positions, including pipe fitters, iron workers, millwrights, boilermakers, carpenters, electricians, and other trades, are estimated to have a payroll of about $10 million over the course of the construction. Day-to-day operation of Cambridge Station will require two to three full-time employees after construction.

The proposed Cambridge Station project will contribute approximately $350,000 in property taxes for Isanti County and the Cambridge and Braham School Districts. The operating staff associated will continue to pay payroll taxes.

Similar to construction, the operation and maintenance of a power plant has a multiplier effect of 8.9 jobs and $0.2339 in earnings for the same dollar amounts invested.[49]

Demographic changes to the local area attributable to the construction of the proposed Cambridge Station could consist of population increases from relocating construction workers and families. Workers employed to construct the proposed project, and who are currently living within the regional area, are not expected to relocate. These persons will commute to work, some from significant distances.

[48] Illuminating Engineering Society of North America. 1993. IES Handbook 8th Edition. New York: IESNA and Illuminating Engineering Society of North America. 1984. Lighting for Parking Facilities. RP-20. New York: IESNA

[49] Socioeconomic Impacts of Power Plants, EPRI, Palo Alto, CA: EA-2228

The Electric Power Research Institute ("EPRI") report, *Socioeconomics of Power Plants*, indicates that construction workers will travel an average of 73 miles one-way on a daily basis to a jobsite, even up to a maximum of 115 miles one way.[50] The study, which analyzed the commuting patterns of workers on several electric generating facility projects, concluded that the long commuting distances were acceptable to workers due to the temporary nature of construction employment at an electric generating facility site.

A small increase in the local area population attributable to the plant construction can be anticipated.

The operations personnel will not be required until the final months of construction. At approximately that time, they would be selected from the local pool or relocate on a permanent basis.

Given the temporary duration of employment, it is assumed that construction personnel who relocate will rent an apartment or home during employment. The operations personnel and families will most likely purchase living accommodations due to the lengthy expected plant life.

The supply of housing in the study area can easily accommodate the small number of relocating workers and families.

Since the population increase during the construction period is expected to be limited, the increased demand for school, hospital, fire and ambulance, police, and utility services will not be significant. Similarly, since the number of employees required after the construction period and during the facility's operational life is small, no significant impact will occur on the demand for other community facilities and services due to relocating personnel.

The Cambridge Station will not require extraordinary public services nor strain the public infrastructure. Construction and operating simplicity associated with combined cycle technology result in minimal burden on roadways and public services.

6.8 WATER RESOURCES

Surface Water

The proposed Cambridge Station project will not significantly impact area water bodies.

Groundwater

The estimated annual groundwater appropriation for the proposed Cambridge Station project is relatively small and is not expected to result in any adverse impacts on the aquifer and regional water supplies or have an adverse impact on any existing potable wells in the area.

[50] Socioeconomic Impacts of Power Plants, EPRI, Palo Alto, CA: EA-2228

Wetlands/Floodplains

No wetlands will be disturbed by construction or operation of the proposed Cambridge Station project.

Stormwater Management

Owners and operators of construction activity disturbing one acre or more of land need to obtain a National Pollution Discharge Elimination System and State Disposal System permit (NPDES/SDS). Regulated parties must develop a Storm-water Pollution Prevention Plan (SWPPP).[51]

The SWPPP must be completed prior to submitting the permit application and before beginning construction. The plans must:

- Describe the nature of the construction activity,
- Address the potential for sediment and pollutant discharges from the site,
- Identify someone to oversee BMP implementation,
- Identify chain of responsibility for general contractor and owner,
- Identify temporary sediment basins, if more than 10 acres are disturbed and drain to a single point of discharge,
- Identify permanent storm-water management system,
- Identify erosion prevention practices,
- Identify sediment control practices,
- Identify dewatering and basin draining practices,
- Identify inspection and maintenance practices,
- Identify pollution prevention management measures,
- Retain records,
- Describe the timing of BMP installation,
- Location and type of temporary and permanent BMPs,
- Include standard plates and specifications of BMPs,
- Include a site map identifying pertinent data.

A combination of control measures will be implemented to retain sediment from disturbed areas during construction. Erosion/sediment controls to be implemented during initial construction activities are listed as follows:

- Maintain a vegetative buffer zone between disturbed areas and the stormwater outfall;
- Construct and maintain a graveled access road;
- Construct berms and/or ditches and sequence placement of fill in order to contain and/or route runoff from fill areas to the sediment basin; and
- Construct and maintain a silt fence along the toe of the fill area boundary slopes.

[51] http://www.pca.state.mn.us/water/stormwater/stormwater-c.html

When a project replaces vegetation or other pervious surfaces with one or more acres of cumulative impervious surface, the runoff from the new impervious surface must be treated by one of the following methods:[52]

- Wet sedimentation basin
- Infiltration/filtration
- Regional ponds
- Combination of practices
- Alternative method, pending MPCA approval.

Erosion/sediment controls to be implemented during later construction activities include the following:

- Contain and/or route stormwater from the fill area to sediment basin; and
- Maintain existing vegetative buffers, inlet protection, and silt fences.

As a permanent stabilization measure to be implemented during construction, vegetative cover will be established on the fill area side slopes by sodding or hydroseeding with mixtures that include native grasses depending on local requirements.

Storm water drainage patterns from the service building area north of 349th Avenue NE will be unchanged. Storm water from the portion of the site south of 349th Avenue NE will be routed to a new water retention basin constructed near the south end of the site.

The retention pond will have a controlled outlet that will discharge water to a drainage swale from the south edge of the site to a wetland located about 300 feet south. GRE will obtain a drainage easement from the adjacent property owner to allow for the discharge through the drainage swale. The wetland discharges to the southwest through an unnamed creek that intersects Beckins Creek about one mile southwest of the site. Beckins Creek discharges to the Rum River about another 1.5 miles downstream.

Wastewater Management

Process wastewater, consisting primarily of evaporative cooler blow down water, will also be routed to the same retention pond.

The expected annual discharge volume from the retention basin is on the order of 4.8 million gallons, approximately 1.8 million gallons from evaporative cooler blow down and 3 million gallons from storm water runoff.

The wastewater discharged from this facility will consist of multi-cycle cooling water. It is anticipated that the required cooling water will be obtained from a groundwater source and will contain minimal additives. Expected chemical and thermal characteristics of the wastewater discharged are anticipated to be similar to that of wastewater discharged from other similar GRE

[52] http://www.pca.state.mn.us/water/stormwater/stormwater-c.html

facilities, such as their Pleasant Valley and Lakefield Junction facilities. The wastewater effluent characteristics of these facilities were reviewed by GRE and indicate that there no anticipated chemical and thermal issues with the wastewater from the proposed facility.

6.9 WASTE MANAGEMENT & DISPOSAL

As described in Subsection 2.1.5, spent hazardous substances such as oil periodically pumped from the oil/water separators, turbine wash water and periodic chemical cleaning wastes will be removed from the plant by a licensed hauler for disposal at a licensed facility. GRE will privately contract with local waste haulers for collection and disposal of all non-hazardous solid wastes generated at the facility.

6.10 NOISE

Operation of the new generation unit will result in an increase in frequency of operational noises, but not a significant increase in maximum noise levels at nearby residences. The Cambridge Station will not result in any violation of Minnesota Noise Standards at the residences located near the facility.

Noise will be generated during the construction and operation of the proposed Cambridge Station project. Construction noise will be predominantly intermittent sources originating from diesel engine-driven construction equipment. Potential noise impacts will be mitigated by proper muffling equipment fitted to construction equipment and restricting activities conducted during nighttime hours.

Noise from the operation of the new CTG is expected to be predominantly low frequency noise, as is noise from traffic. Noise from operation will not significantly impact the acoustical environment given the high background noise levels (particularly in low frequencies) from nearby Minnesota Highway 65 and 349th Avenue NE, the distance of the CTG from adjacent properties and the noise control technology that will be employed by the new generating unit.

Noise from combustion turbine operation is a result of air flow through the combustion air intake and from the exhaust gases discharging from the stack. The air inlet will be appropriately sized and fitted with diffusers to minimize velocity and therefore the noise of air moving into the inlets. The stack will be fitted with silencers to reduce the noise of exhaust gases leaving the plant.

The locations of the two residences closest to the proposed CTG location are highlighted on **Figure 2**. Preliminary noise calculations indicate that the Minnesota L_{50} nighttime standard of 50 decibels would not be exceeded during CTG operation at distances greater than 600 feet from the new CTG. The nearest residence is approximately 1,300 feet southwest of the proposed CTG location.

6.11 PUBLIC SERVICES

Public services in the Cambridge area will be adequate for the construction and operation of the proposed Cambridge Station project. These services include water and sewer, waste collection and disposal and fire and police.

All of the city's emergency services can be reached by dialing 911.

7.0 SUMMARY OF MITIGATIVE MEASURES

The construction and operation of a new generating facility will unavoidably result in some environmental effects. This section discusses mitigative measures that will be implemented to address unavoidable effects from the proposed Cambridge Station project.

Air Quality

Air pollution control equipment will be included to achieve and maintain compliance with permitted air emission levels. The combustion turbines will be equipped with dry low NOx combustors to limit the production of NOx during combustion. These combustors are designed to maintain the fuel-to-air ratio to a near stoichiometric level, where the quantity of oxygen in the air introduced into the combustion process is just enough to allow the fuel to burn. This "lean" ratio results in a relatively cool combustion zone. NOx is produced in high-temperature zones; therefore, the lower temperature in the combustion zone will reduce the NOx produced.

Inherently, natural gas combustion produces little or no particulate or sulfur emissions and, as such, no specific control equipment is required for those pollutants.

Effect of New Noise Source

Noise levels from the CTG are expected to range from approximately 49 dBA to 52 dBA at the fence line. Since the Minnesota Noise Rules would require that the facility not cause noise levels at the nearest residential receptor to exceed 60 dBA during daytime hours or 50 dBA during nighttime hours, the Cambridge Station is expected to fully comply with the state's established noise standards.

The specific type and amount of noise control needed to achieve compliance with the State of Minnesota noise control standards will be selected during the detailed design phase of the proposed project. A successful mitigation program will likely consist of the following components:

- Combustion Turbine Exhaust Silencers;
- Combustion Turbine Air Intake Silencers; and
- Low-Noise Fuel Gas Metering Station.

8.0 Acronyms, Abbreviations and Definitions

ADT	average daily traffic
ANSI	American National Standard Institute
BACT	Best Available Control Technology
BMPs	Best Management Practices
Btu/kWhr	British thermal units per kilowatt-hour
CAA	Clean Air Act
CERCLA	Federal Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
CESQG	Conditionally Exempt Small Quantity Generator
CFR	Code of Federal Regulations
CGTs	Combustion gas turbines
CMP	Crop Management Program
CO	Carbon monoxide
CO_2	Carbon dioxide
CON	Certificate of Need
CT	Combustion Turbine
CY	Cubic yards
dBA	A-weighted decibel
DLN	Dry Low-NO_X
DOC	Department of Commerce
DSM	Demand Side Management
EA	Environmental Assessment
ECS	Ecological Classification System
EIS	Environmental impact statement
EMF	Electromagnetic field
EPA	U.S. Environmental Protection Agency
EQB	Environmental Quality Board
ELCR	Excess Lifetime Cancer Risk
FAA	Federal Aviation Administration
FEMA	Federal Emergency Management Agency
FEP	Faribault Energy Park
FHWA	Federal Highway Administration
FIRM	Flood Insurance Rate Map
GE	General Electric
GHG	Greenhouse gas emissions
GISB	Gas Industry Standards Board
gpd	Gallons per day
HBGP	High Bridge Generating Plant
HBRP	High Bridge Repowering Project
HCP	Habitat Conservation Plan
HRSG	Heat Recovery Steam Generator
HVTL	High Voltage Transmission Line
IES	Illuminating Engineering Society

ISTS	Individual Septic Treatment System
kV	Kilovolt
LAER	Lowest Available Emission Rate
LEPGP	Large Electric Power Generating Plant
LOS	Level-of-service
LUG	Local Unit of Government
MW	Megawatts
MDH	Minnesota Department of Health
MDNR	Minnesota Department of Natural Resources
MDOT	Minnesota Department of Transportation
MMPA	Minnesota Municipal Power Agency
MPCA	Minnesota Pollution Control Agency
NAAQS	National Ambient Air Quality Standards
NET	National Emission Trends
NEPA	National Environmental Policy Act
NH3	Ammonia
NTI	National Toxics Inventory
NNG	Northern Natural Gas
NOx	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
OAHP	Office of Archaeology and Historic Preservation
PAH	Polycyclic aromatic hydrocarbons
Pb	Lead
PEMA	Palustrine emergent temporarily flooded
PEMC	Palustrine emergent seasonally flooded
PFOA	Palustrine forested temporarily flooded
PESCP	Permanent Erosion and Sediment Control Plan
PM	Particulate matter
PM_{10}	Particulate matter less than 10 microns in diameter
$PM_{2.5}$	Particulate matter less than 2.5 microns in diameter
POWHX	Palustrine open water permanently flooded excavated
ppb	Parts per billion
ppm	Parts per million
PSD	Prevention of Significant Deterioration
psi	Pounds per square inch
PSS	Potential Site Study
PUC	Public Utility Commission
SARA	Federal Superfund Amendments and Reauthorization Act of 1986, as amended
SCR	Selective catalytic reduction
SDS	State Disposal System
SIL	Significant Impact Levels
SO_2	Sulfur dioxide
SPCC	Spill Prevention Control and Countermeasure
STG	Steam turbine generator

USFWS	U.S. Fish and Wildlife Service
TESCP	Temporary Erosion and Sediment Control Plan
TSP	Total Suspended Particulate Matter
UHC	Unburned Hydrocarbon
USACE	United States Army Corp of Engineers
VOC	Volatile organic compounds

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TABLES

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Table 1
Operational Information Summary

Description	Project Data	
	WINTER	SUMMER
Unit Type	Simple Cycle Combustion Turbine	
Capability	170 MW	190 MW
Expected Annual Capacity Factor	5-10 percent	
Expected Heat Rate	10,200Btu/kWh (HHV)	9,720Btu/kWh (HHV)
Expected Efficiency	35 percent	37 percent
Fuel Type	Natural gas (only)	
Fuel Use Rate	1.546 MCf/hour	1.771 MCf/hour
Expected Annual Fuel Use	1.4-1.5 million MCf	
Expected Groundwater Withdrawal Rate	108 gpm	
Expected Annual Groundwater Appropriation	4.7 million gallons	
Expected Annual Wastewater/Stormwater Discharge	~ 4.8 million gallons	

Source: Site Permit Application, Cambridge Station Project, T 3-1. March 11., 2005.

Table 2
Typical Natural Gas-Fired Power Generating Facility Chemicals

Chemical	Use	Quantity Stored Onsite	Form/Type
Laboratory reagents	Various	Small amounts, generally less than 5 pounds each	Liquid and granular
Mineral insulating oil, C-10	Transformer systems	15,000 gallons	Insulating fluid
Sulfur hexafluoride, (SF_6)	Substation electrical insulating gas	33 pounds	Insulating gas
Lubrication oil	Rotating equipment	3,500 gallons	CTGs bearing lubricating oil
Diesel fuel	Fuel for diesel engine driven fire pump	300 - 500 gallons	Diesel fuel
Various detergents	Combustion turbine on/off line water wash skid	200 gallons stored	Liquid
Compressed gases			
Carbon dioxide (CO_2)	Fire Protection System	8 tons	Compressed gas
FM200	Fire Protection System	300 pounds	Compressed gas
Welding Gases	Maintenance	4-100-pound cylinders	Compressed gas

*Chemical cleaning agents shown are those typically used. A decision on which chemicals and quantity will actually be used will be made as the project design continues.

Source: Site Permit Application, Cambridge Station Project, T 3-2. March 11,. 2005.

Table 3
Preliminary Permitting & Approval Requirements

Agency	Permit/Approval	Regulated Activity
	FEDERAL	
EPA	Spill Prevention Control & Countermeasure Plan	Facilities w/ above ground oil storage capacity of greater than 1,300 gallons.
EPA	Risk Management Plan	Potential accidental releases of hazardous chemicals that are used or stored onsite in greater than threshold quantities (Title III of CAAA).
DOE	Alternate Fuels Capability Certification	Baseload facility using natural gas.
FAA	Notice of Proposed Construction or Alteration	Construction of an object which has the potential to affect navigable airspace (height in excess of 200' or within 20,000' of an airport).
FERC	Exempt Wholesale Generator Status	Selling electric energy at wholesale to a utility or other generator.
	STATE	
MPCA	Air Emissions Permit (Amendment)	Construction, installation or alteration of an air contamination source.
MPCA	Title IV Acid Rain Operating Permit	Title IV of CAAA, applicable to fossil fuel fired units > 25 MW.
MPCA	Title V Operating Permit	Title V of CAAA or Federally Enforceable State Operating Permit for significant air emission sources.
MPCA	Hazardous Waste SQG Registration	Generation of small quantities of hazardous waste.
MPCA	Above ground Storage Tank (AST) Permit	Facilities that have > one million gallons of total capacity.
MPCA	NPDES Stormwater Construction Permit	Discharge of storm waters during construction of facility.
MPCA	NPDES Stormwater Operation Permit	Discharge of storm waters during operation of facility.
MPCA	NPDES Wasterwater Discharge	Discharge of wastewaters during operation of facility.
State Historic Preservation Office	Archeological and Historical Review	Activities that could potentially affect archeological or historical resources.
MDNR	Groundwater Appropriation	A water use (appropriation) permit from DNR Waters is required for all users withdrawing more than 10,000 gallons of water per day or 1 million gallons per year.
City/County/Tsp	Site Plan Approval	Establishment of power generation facilities as a permitted use.
City/County/Twp	Building Permit/Architectural Review/Fire Safety Approval	Construction of facility.
City/County/Tsp	Soil and Sedimentation Control Permit	Control of soil erosion.
City/County/Tsp	Individual Septic Treatment System	Design, construction and discharge of sanitary wastewater.
City/County/Tsp	Certificate of Occupancy	License to operate facility

EPA – Environmental Protection Agency; DOE – Department of Energy; FAA – Federal Aviation Administration; FERC – Federal Energy Regulatory Commission; COE – Corp of Engineers; MPCA – Minnesota Pollution Control Agency; MnDOT – Minnesota Department of Transportation; MDNR – Minnesota Department of Natural Resources

Table 4
Comparison of Alterative: Operational

Characteristic	Project	Oil-Fired Simple-Cycle	Ethanol-Fired Simple-Cycle	MN Rule
Facility Description				
Unit Type	F-Class	F-Class	F-Class	
Prime Mover	Combustion Turbine	Combustion Turbine	Combustion Turbine	
Number of Units	1	1	1	
Summer Capability (site specific)[1]	170 MW	164 MW	164 MW	7849.0250, A(1)
Winter Capability (site specific)	190 MW	190 MW	190 MW	7849.0250, A(1)
Operating Cycle	Simple-cycle	Simple-cycle	Simple-cycle	7849.0250, A(2)
Expected Annual Capacity Factor	9.6%	9.6%	9.6%	7849.0250, A(2)
Expected Heat Rate/Efficiency (Summer site specific)[2]	10,200 Btu/kWh (HHV)/35%	10,450 Btu/kWh (HHV)/34.6%	10,450 Btu/kWh (HHV)/34.6%	7849.0250, A(4)
Expected Heat Rate/Efficiency (Winter site specific)[2]	9,730 Btu/kWh (HHV)/37%	9,900 Btu/kWh (HHV)/36.5%	9,900 Btu/kWh (HHV)/36.5%	7849.0250, A(4)
Heat Rejected through exhaust (Summer)	1,013 MMBtu/hr	1,061 MMBtu/hr	1,061 MMBtu/hr	
Heat Rejected through exhaust (Winter)	1,188 MMBtu/hr	1,224 MMBtu/hr	1,224 MMBtu/hr	
Fuel Description				
Fuel Source: Natural Gas only	Northern Natural Gas Pipeline	Regional Refineries	Regional Ethanol Plants	7849.0320, C(1)
Fuel Requirement: (Summer)[2]	1,546 MCf/hr	12,695 gal/hr	22,550 gal/hr	7849.0320, C(2)
Fuel Requirement: (Winter)[2]	1,771 MCf/hr	13,933 gal/hr	24,750 gal/hr	7849.0320, C(2)
Expected Annual Fuel Requirement	1,305,360	11,109,511 gal/yr	19,734,000 gal/yr	7849.0320, C(2)
Heat Input (Summer - HHV)[2]	1554 MMBtu/hr	1,714 MMBtu/hr	1,714 MMBtu/hr	7849.0320, C(3)
Heat Input (Winter - HHV)[2]	1780 MMBtu/hr	1,881 MMBtu/hr	1,881 MMBtu/hr	7849.0320, C(3)
Fuel Heat Content	1.005 MMBtu/MCf	0.137 MMBTU/gal	0.0841 MMBTU/gal	7849.0320, C(4)
Fuel Sulfur Content	5.5 mg/m^3	<0.05 percent	Unknown	7849.0320, C(5)
Fuel Ash Content	None	Trace	Unknown	7849.0320, C(5)
Fuel Moisture Content	<80 mg/m^3	Trace	Unknown	7849.0320, C(5)
Water Use				
Estimated maximum groundwater pumping rate[3]	108 gpm	454 gpm	611 gpm	7849.0320, E(1)
Estimated maximum surface water appropriation[3]	0 ft^3/sec	0 ft^3/sec	0 ft^3/sec	7849.0320, E(1)
Estimated annual groundwater appropriation[4]	3. million gal/yr	13 million gal/yr	17 million gal/yr	7849.0320, E(2)
Annual consumption[4]	9.2 acre-feet	38.6 acre-feet	52.0 acre-feet	7849.0320, E(3)
Discharges to water	2.1 million gal/yr	2.1 million gal/yr	2.1 million gal/yr	
Estimated Emission Rates (lbs/hr)				
CO[2]	37	47	47[5]	7849.0320, D(1)
SO_2[2]	5.7	91	91[5]	7849.0320, D(1)
NO_x[2]	169	327	327[5]	7849.0320, D(1)
PM_{10}[2]	15	36	36[5]	7849.0320, D(1)
Other Information				
Land Requirements	2.5 acres	2.5 acres	2.5 acres	
Traffic	Slight increase due to on-site operators	Increased due to fuel deliveries	Increased due to fuel deliveries	
Radioactive Releases	None	None	None	
Solid Wastes Produced	Construction packaging, office waste, waste lubricating oils	Construction packaging, office waste, waste lubricating oils	Construction packaging, office waste, waste lubricating oils	
Noise	≤ 63 dB(A) @ 400 ft.	≤ 63 dB(A) @ 400 ft.	≤ 63 dB(A) @ 400 ft.	
Work Force	2 to 3 FTE	2 to 3 FTE	2 to 3 FTE	
Transmission Requirements	Upgrade 3 sections of 69-kV lines	Upgrade 3 sections of 69-kV lines	Upgrade 3 sections of 69-kV lines	

1 With evaporative cooler in service.
2 Under base load operations.
3 When unit is on-line.
4 Assuming a 9.6% annual capacity factor and utilization of evapoartive cooler for 5.7% of annual operation.
5 Emissions estimates are typically based on operating data from other units in operation. No ethanol-fired combustion turbines are in operation and no manufacturers have tested ethanol-fired turbines. Therefore, emissions are assumed to be equivalent to those from firing fuel oil.

Table 5
Comparison of Alterative: Economic

Item	Units	Project	Oil-Fired Simple-Cycle	Ethanol-Fired Simple-Cycle	Assumptions	MN Rule
Project Description						
Base Capability (Summer, site-specific rating)	MW	170	164	164	Manufacturer *pro forma* estimate	7849.025, A(1)
Cost Basis	Cal Yr	2004	2004	2004		
Life of Project	Years	30	30	30	Typical accounting life	7849.025, C(2)
Operating Cycle		Simple	Simple	Simple		7849.025, A(2)
Annual Capacity Factor	%	9.6%	9.6%	9.6%	PVS experience	7849.025, A(2)
Annual Operating Time	Hours	840	840	840	Formula	
Average Annual Availability	%	97.5	97.5	97.5	PVS ops experience	7849.025, C(3)
Fuel Type		Nat Gas	No. 2 Fuel Oil	Ethanol		7849.025, A(3)
Heat Input (HHV)	MMBtu/hr	1,554	1,714	1,714	PVS ops experience	
Heat Rate (HHV) - Summer Rating	Btu/kWh	10,200	10,450	10,450	PVS ops experience	7849.025, A(4)
Efficiency (HHV) - Summer Rating	%	35.4	34.6	34.6	Formula	7849.025, C(8)
Project Capital Cost	$/kW	406	430	443	Overnight cost w/o IDC	
Fixed O&M Costs	$/kW-yr	3.46	3.46	3.46	PVS experience	
Fuel Costs	$/MMBtu	5.73	7.45	20.22	EIA *2005 AEO* plus transport & balancing	7849.025, C(4)
Non-Fuel Variable O&M Costs	$/MWh	8.41	12.62	12.62	Includes fired-hour costs & start charge	7849.025, C(5)
Capacity Costs (Fixed)						**7849.025, C(1)**
Total Project Capital Cost	$	69,020,000	70,520,000	72,652,000	Formula	
Annual Fixed O&M	$	588,200	567,440	567,440	Formula	
Total Annual Fixed Costs	$	6,523,920	6,632,160	6,815,512	8.6% annual FCs + Fixed O&M	
Project Capacity Cost	$/kW-yr	38.38	40.44	41.56	Formula	
Project Capacity Cost	$/kWh	0.046	0.048	0.049	Formula	
Production Costs (Variable)						
Net Annual Generation	MWh	142,800	137,760	137,760	Formula	
Annual Fuel Consumption	MMBtu	1,305,360	1,439,760	1,439,760	Formula	
Annual Fuel Cost	$	7,483,015	10,728,673	29,111,947	Formula	
Annual Non-Fuel Variable O&M Cost	$	1,200,948	1,738,531	1,738,531	Formula	
Total Project Variable Generation Cost	$	8,683,963	12,467,204	30,850,478	Formula	
Project Fuel Cost	$/kWh	0.052	0.078	0.211	Formula	7849.025, C(4)
Project Total Energy Cost	$/kWh	0.061	0.090	0.224	Formula	
Total Cost	**$/kWh**	**0.106**	**0.139**	**0.273**	**Formula**	**7849.025, C(6)**

Table 6
Cambridge ♦ Elk River Site Comparison

Project Description				
	Units	**Cambridge**	**Elk River**	
Base Capability	MW	170	170	
Cost Basis	Cal Yr	2004	2004	
Life of Project	Yr	30	30	
Capital Cost ($000s)				
Power Plant	($)	54,215	59,084	
Gas Supply/Interconnection	($)	1,090	1,862	
Transmission Infrastructuree	($)	13,705	6,145	
Total Capital Costs	($)	69,010	67,091	
Total Unit Cost ($/kW)	($)	406	395	
Year 2 Fixed Costs ($000s)				
Annual Project Int/Dep	($)	6,743	6,461	
Annual Fixed O&M	($)	524	474	
Annual Taxes	($)	179	1,063	
Annual Insurance	($)	229	278	
Total Annual Fixed Costs	($)	7,675	8,276	
Year 2 Unit Fixed Costs	$/kW/Yr	45.14	48.68	
Levelized Cash Flow	$/kW/Yr	45.20	48.80	
Site Specific Factors				
Transmission Capability	+ / - / 0	+	+	
Gas Supply	+ / - / 0	+	0	
Land use	+ / - / 0	+	+	
Water	+ / - / 0	+	+	
Roads	+ / - / 0	+	+	
Local Government Support	+ / - / 0	+	-	
Environmental Impact	+ / - / 0	+	+	

+ / - / 0, positive, negative, neutral;
Source: GRE Alternative Evaluation & Site Selection Study for the Cambridge Peaking Plant, T 5-1 & 5-2. April, 2005.

Table 7
NAAQS Air Pollution Concentration Standards

Pollutant	Averaging Period	Standard	Primary NAAQS	Secondary NAAQS
Ozone	1-hour	Not to be at or above this level on more than 3 days over 3 years	125 ppb	125 ppb
Ozone	8-hour	The average of the annual 4th highest daily 8 hour maximum over a 3 year period is not to be at or above this level.	85 ppb	85 ppb
Carbon Monoxide	1-hour	Not to be at or above this level more than once per calendar year.	35.5 ppm	35.3 ppm
Carbon Monoxide	8-hour	Not to be at or above this level more than once per calendar year.	9.5 ppm	9.5 ppm
Sulfur Dioxide	3-hour	Not to be at or above this level more than once per calendar year.	NA	550 ppb
Sulfur Dioxide	24-hour	Not to be at or above this level more than once per calendar year.	145 ppb	NA
Sulfur Dioxide	Annual	Not to be at or above this level.	35 ppb	NA
Nitrogen Oxide	Annual	Not to be at or above this level.	54 ppb	54 ppb
Particulate Matter ($\leq$10 microns)	24-hour	Not to be at or above this level on more than 3 days over 3 years with daily sampling.	155 ug/m3	155 ug/m3
Particulate Matter ($\leq$10 microns)	Annual	The 3 year average of annual arithmetic mean concentrations at each monitor w/in an area is not to be at or above this level.	51 ug/m3	51 ug/m3
Particulate Matter ($\leq$2.5 microns)	24-hour	The 3 year average of the annual 98th percentile for each population-orriented monitor w/in an area is not to be at or above this level.	66 ug/m3	66 ug/m3
Particulate Matter ($\leq$2.5 microns)	Annual	The 3 year average of annual arithmetic mean concentrations from single or multiple community-oriented monitors is not to be at or above this level.	15.1 ug/m3	15.1 ug/m3
Lead	Quarter	Not to be at or above this level.	1.55 ug/m3	1.55 ug/m3

Primary NAAQS: the levels of air quality that the EPA judges necessary, with an adequate margin of safety, to protect the public health.
Secondary NAAQS: the levels of air quality that the EPA judges necessary to protect the public welfare from any known or anticipated adverse effects.

Table 8 Wetlands Summary		
Distance and Direction from Project Site	**Cowardin Classification**	**Plant Community Type**
300 ft S	PSS1/EMBd/ PEMFd/PUBGx	Scrub-shrub/ Semi-permanently flooded emergent marsh (partially drained) (71-49W)
250 feet W	PFO2/1B	Tamarack and mixed hardwood swamp
400 feet ENE	PEMAd	Temporarily flooded emergent marsh (drained and farmed)
650 ft N	PEMB	Emergent marsh

Source: Site Permit Application. Cambridge Station Project. T 4-4. March 11., 2005.

Table 9
Historical Population

Area	1990 Census	2000 Census	% Increase
Cambridge	5094	5520	8.4
Isanti County	25,921	31,287	20.7
Twin Cities Metro	2,288,729	2,642,056	15.4
State of Minnesota	4,375,099	4,919,479	12.4

Source: Minnesota Planning Agency

Table 10
State of Minnesota Noise Standards

Noise Area Classification	Daytime (dBA)		Nighttime (dBA)	
	L_{50}	L_{10}	L_{50}	L_{10}
1 (Residential)	60	65	50	55
2 (Commercial)	65	70	65	70
3 (Industrial)	75	80	75	80

dBA = decibels, A-weighted scale; L_{10} = sound pressure level which is exceeded 10% of the time period; L_{50} = sound pressure level which is exceeded 50% of the time period.

Table 11
Air Pollution Emissions

Air Pollutant	Annual Emissions (tons/year)	Emission Factor[1] (lbs/hr per CTG)
Particulate Matter (PM/PM_{10})	5.8	12.9
Carbon Monoxide (CO)	14.4	32
Nitrogen Oxides (NO_x)	66	148
Sulfur Dioxide (SO_2)	1.4	2.9
Volatile Organic Material (VOC)	3.6	8.2
Hazardous Air Pollutants		
Formaldehyde	0.6	
Toluene	0.1	
Xylene	0.04	
Acetaldehyde	0.04	
Ethyl Benzene	0.02	
Propylene Oxide	0.02	
Benzene	0.008	
Acrolein	0.004	
PAH	0.0016	
Naphthalene	0.0008	
1,3-Butadiene	0.0004	

[1]Emission factors for the general pollutants from manufacturer data.
[2]Based on 876 operating hours
[4] PAH is polycyclic aromatic hydrocarbon.

Source: Site Permit Application, Cambridge Station Project, T 4-1. March 11., 2005.

Table 12
Predicted Ambient Air Concentrations

Pollutant	Standard/ Averaging Period	Modeled Concentration ug/m^3	Background Concentration ug/m^3	Total Concentration ug/m^3	Standard ug/m^3
Formaldehyde	Annual	0.000031	1.5	NA	NA
Nitrogen Dioxide	Annual	0.0045	20	1	100
Sulfur Dioxide	Annual	0.00015	0.9	1	80
	24-hour	0.0075		5	365
	3-Hour	0.051		25	1300
	1-Hour	0.14		NA	1300

Source: Site Permit Application, Cambridge Station Project, T 4-2. March 11,, 2005.